DEVON ENERGY CORP/DE
Form 10-K
February 25, 2010

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, 2009

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 of 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

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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) 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. o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 common stock held by non-affiliates of the registrant as of June 30, 2009, was approximately $24.0 billion, based upon the closing price of $54.50 per share as reported by the New York Stock Exchange on such date. On February 15, 2010, 446.8 million shares of common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy statement for the 2010 annual meeting of stockholders Part III

DEVON ENERGY CORPORATION

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TO THE SECURITIES AND EXCHANGE COMMISSION

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DEFINITIONS

Bbl or Bbls means barrel or barrels.

Bcf means billion cubic feet.

Bcfe means billion cubic feet of gas equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

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

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

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

Federal Funds Rate means the interest rate at which depository institutions lend balances at the Federal Reserve to other depository institutions overnight.

FPSO means floating, production, storage and offloading facilities.

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

International means the discontinued operations of Devon that encompass oil and gas properties that lie outside the United States and Canada.

LIBOR means London Interbank Offered Rate.

MBbls means thousand barrels.

MBoe means thousand Boe.

Mcf means thousand cubic feet.

MMBbls means million barrels.

MMBoe means million Boe.

MMBtu means million Btu.

MMcf means million cubic feet.

MMcfe means million cubic feet of gas equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.

NGL or NGLs means natural gas liquids.

North American Onshore means our operations encompassing oil and gas properties in the continental United States and Canada.

NYMEX means New York Mercantile Exchange.

Oil includes crude oil and condensate.

SEC means United States Securities and Exchange Commission.

U.S. Offshore means the operations of Devon encompassing oil and gas properties in the Gulf of Mexico.

U.S. Onshore means the operations of Devon encompassing oil and gas properties in the continental United States.

INFORMATION 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

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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 used to prepare the December 31, 2009 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 similar terminology. A 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, including the supply and demand for oil, gas, NGLs and other products or services, and the prices of oil, gas, NGLs, including regional pricing differentials, and other products or services;

production levels, including Canadian production subject to government royalties, which fluctuate with prices and production, and international production governed by payout agreements, which affect reported production;

reserve levels;

competitive conditions;

technology;

the availability of capital resources within the securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks;

capital expenditure and other contractual obligations;

currency exchange rates;

the weather;

inflation;

the availability of goods and services;

drilling risks;

future processing volumes and pipeline throughput;

general economic conditions, whether internationally, 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; 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 exploration, development and production of natural gas and oil. Our oil and gas operations are concentrated in various North American onshore areas in the United States and Canada. We also have offshore operations that are situated principally in the Gulf of Mexico and regions located offshore Azerbaijan, Brazil and China.

To complement our upstream oil and gas operations, we have marketing and midstream operations primarily in North America. With these operations, we market gas, crude oil and NGLs. We also construct and operate pipelines, storage and treating facilities and natural gas processing plants. These midstream facilities are used to transport oil, gas, and NGLs and process natural gas.

We began operations in 1971 as a privately held company. We have been publicly held since 1988, and our common stock is listed on 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

As an enterprise, we aspire to be the premier independent natural gas and oil company in North America. To achieve this, we continuously strive to optimize value for our shareholders by growing reserves, production, earnings and cash flows, all on a per share basis. We do this by:

- exercising capital discipline;
- investing in oil and gas properties with high operating margins;
- balancing our reserves and production mix between natural gas and liquids;
- maintaining a low overall cost structure;
- improving performance through our marketing and midstream operations; and
- preserving financial flexibility.

Over the past decade, we captured an abundance of resources by carrying out this strategy. We pioneered horizontal drilling in the Barnett Shale and extended this technique to other natural gas shale plays in the United States and Canada. We became proficient with steam-assisted gravity drainage with our Jackfish oil sands development in Alberta, Canada. We achieved key oil discoveries with our drilling in the deepwater Gulf of Mexico and offshore Brazil. We have more than tripled our proved oil and gas reserves since 2000, and have also assembled an extensive inventory of exploration assets representing additional unproved resources.

Building off our past successes, in November 2009, we announced plans to strategically reposition Devon as a high-growth, North American onshore exploration and production company. As part of this strategic repositioning, we plan to bring forward the value of our offshore assets located in the Gulf of Mexico and countries outside North America by divesting them.

This repositioning is driven by our desire to unlock and accelerate the realization of the value underlying the deep inventory of opportunities we have. We have assembled a valuable portfolio of offshore assets, and we have a considerable inventory of premier North American onshore assets. However, our North American onshore assets have consistently provided us our highest risk-adjusted investment returns. By selling our offshore assets, we can more aggressively pursue the untapped value of these North American onshore opportunities. Besides reducing debt, the offshore divestiture proceeds are expected to provide significant funds to redeploy into our prolific North American onshore opportunities. With these added funds, we plan to accelerate the growth and realization of the value of our North American onshore assets.

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Presentation of Discontinued Operations

As a result of the planned divestitures of our offshore assets, all amounts in this document related to our International operations are presented as discontinued. Therefore, financial data and operational data, such as reserves, production, wells and acreage, provided in this document exclude amounts related to our International operations unless otherwise provided.

Even though we are also divesting our U.S. Offshore operations, these properties do not qualify as discontinued operations under accounting rules. As such, financial and operational data provided in this document that pertain to our continuing operations include amounts related to our U.S. Offshore operations. Where appropriate, we have presented amounts related to our U.S. Offshore assets separate from those of our North American Onshore assets.

Development of Business

Since our first issuance of common stock to the public in 1988, we have executed strategies that have always been focused on growth and value creation for our shareholders. We increased our total proved reserves from 8 MMBoe at year-end 1987 to 2,733 MMBoe at year-end 2009. During this same time period, we increased annual production from 1 MMBoe in 1987 to 233 MMBoe in 2009. Our expansion over this time period is attributable to a focused mergers and acquisitions program spanning a number of years, as well as active and successful exploration and development programs in more recent years. Additionally, our growth has provided meaningful value creation for our shareholders. The growth statistics from 1987 to 2009 translate into annual per share growth rates of 11% for production and 8% for reserves.

As a result of this growth, we have become one of the largest independent oil and gas companies in North America. During 2009, we continued to build off our past successes with a number of key accomplishments, including those discussed below.

Drilling Success We drilled 1,135 gross wells with a 99% success rate. As a result of our success with the drill-bit, we replaced approximately 213% of our 2009 production. We added 496 MMBoe of proved reserves during the year with extensions, discoveries and performance revisions. These reserve additions were more than double the 233 MMBoe we produced during 2009. Besides increasing our proved reserves, our drilling success was also the main driver of our 5% production growth in 2009.

Barnett Shale We drilled 336 wells in the Barnett Shale field in north Texas in 2009, bringing our total producing wells in the field to almost 4,200 at year end. We exited 2009 with net Barnett Shale production at just over one Bcf of natural gas equivalent per day. We are currently running 16 operated drilling rigs in the Barnett and expect to drill 370 wells in the field in 2010.

Cana-Woodford Shale We drilled 47 successful wells in the Cana-Woodford Shale in western Oklahoma in 2009. We also increased our net production from this important new shale-gas resource by nearly 500% to an average of 39 MMcf of natural gas equivalent per day. We have increased our lease position in the Cana-Woodford Shale to 118,000 net acres and expect to drill approximately 85 wells in the field in 2010.

Haynesville Shale We drilled eight Haynesville Shale wells in the greater Carthage area of east Texas in 2009. These wells have significantly de-risked our 110,000 net Haynesville Shale acres in the Carthage area.

Jackfish In Canada, our 100-percent owned Jackfish oil sands project in Alberta was operational throughout 2009. As measured by production per well and steam-to-oil ratio, Jackfish is one of Canada s most commercially successful steam-assisted gravity drainage projects. In late 2009, Jackfish s gross production reached 33.7 MBbls of oil per day. The addition of four more producing wells is expected to push production to the facility s capacity of 35 MBbls per day in early 2010.

Construction continued throughout 2009 on a second phase of the Jackfish project. Jackfish 2 is also sized to produce 35 MBbls of oil per day and will commence operations in 2011. We expect to file a regulatory application for a third phase of the project in the third quarter of 2010.

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Brazil Offshore Brazil, we participated in two significant deepwater discoveries in 2009. The Devon-operated Itaipu exploratory discovery followed a successful appraisal of the 2008 Wahoo discovery. Both Itaipu and Wahoo are pre-salt prospects located in the Campos Basin.

Financial Information about Segments and Geographical Areas

Notes 20 and 22 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, Natural Gas and NGL Marketing

The spot markets for oil, gas and NGLs are subject to volatility as supply and demand factors fluctuate. As detailed below, we sell our production under both long-term (one year or more) or short-term (less than one year) agreements. Regardless of the term of the contract, the vast majority of our production is sold at variable or market sensitive prices.

Additionally, we may periodically enter into financial hedging arrangements or fixed-price contracts associated 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 and short-term agreements at prices negotiated with third parties. Although exact percentages vary daily, as of January 2010, approximately 81% of our oil production was sold under short-term contracts at variable or market-sensitive prices. The remaining 19% of oil production was sold under long-term, market-indexed contracts that are subject to market pricing variations.

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 January 2010, approximately 86% of our 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 13% of our production was committed under various long-term contracts, which dedicate the gas to a purchaser for an extended period of time, but still at market-sensitive prices. The remaining 1% of our gas production was sold under long-term, fixed-price contracts.

NGL Marketing

Our NGL production is sold under both long-term and short-term agreements at prices negotiated with third parties. Although exact percentages vary, as of January 2010, approximately 90% of our NGL production was sold under short-term contracts at variable or market-sensitive prices. The remaining 10% of NGL production was sold under short-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, gas and NGL production in a timely and efficient manner. Our most significant 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 midstream assets also include our 50% interest in the Access Pipeline transportation system in Canada. This pipeline system allows us to blend our Jackfish heavy oil production with condensate and transport the combined product to the Edmonton area for sale.

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. 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.

Our NGL production is primarily sold to customers engaged in petrochemical, refining and heavy oil blending activities. Pipelines, railcars and trucks are utilized to move our products to market.

During 2009, 2008 and 2007, no purchaser accounted for over 10% of our revenues.

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.

Public Policy and Government Regulation

The oil and gas industry is subject to various types of regulation throughout the world. Laws, rules, regulations and other policy implementations affecting the oil and gas industry have been pervasive and are under constant review for amendment or expansion. Pursuant to public policy changes, 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. Because public policy changes affecting the oil and gas industry are commonplace and because 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 and financial strength.

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, tribal, local and international laws and regulations. These regulations relate to matters that include, but are not limited to:

- acquisition of seismic data;
- location of wells;
- drilling and casing of wells;
- well production;
- spill prevention plans;
- emissions permitting;
- 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;
- calculation and disbursement of royalty payments and production taxes;
- plugging and abandoning of wells;
- transportation of production; and
- in international operations, minimum investments in the country of operations.

Our operations also are subject to conservation regulations, including the regulation of the size of drilling and spacing units or proration units; the number of wells that may be drilled in a unit; the rate of production allowable from oil and gas wells; and the unitization or pooling of oil and 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 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. natural gas and oil 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 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 also have established incentive programs such as royalty rate reductions, royalty holidays, tax credits and fixed rate and profit-sharing royalties 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.

The provincial government of Alberta enacted a new royalty regime effective January 1, 2009. The new regime links royalties to price and production levels and applies to both new and existing conventional oil and gas activities and oil sands projects. This regime has generally reduced our proved reserves and production in Alberta, as well as the related earnings and cash flows. Similar effects have been experienced throughout the oil and gas industry in Alberta. Acknowledging this impact on the industry, the government of Alberta has announced a competitiveness review to assess the impact to the industry as a result of the royalty changes. However, we are uncertain whether the current regime will be modified.

Pricing and Marketing in Canada

Any oil or gas export to be made pursuant to an export contract that exceeds a certain duration or a certain quantity requires an exporter to obtain export authorizations from Canada s National Energy Board (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.

Production Sharing Contracts

Some 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 agency to retain higher fractions of revenue.

Environmental and Occupational Regulations

We are subject to various federal, state, provincial, tribal, local and international laws and regulations concerning occupational safety and health as well as 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 emission of certain gases into the atmosphere;
- 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, is required to be implemented for some international oil and gas operations.

We consider the costs of environmental protection and safety and health compliance necessary and manageable parts of our business. We have been able to plan for and comply with environmental, safety and health initiatives without materially altering our operating strategy or incurring significant unreimbursed expenditures. However, based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and will likely continue to increase. 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.

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Climate Change

Policy makers in the United States are increasingly focusing on whether the emissions of greenhouse gases, such as carbon dioxide and methane, are contributing to the warming of the Earth s atmosphere and other climatic changes. However, there is currently no settled scientific consensus on whether, or the extent to which, human-derived greenhouse gas emissions contribute to climatic change. As an oil and gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop, produce and process oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the oil, gas and NGLs we sell, emits carbon dioxide and other greenhouse gases. As a result, some believe that combustion of carbon-based fuels contributes to climate change.

Despite the lack of a settled scientific consensus on human-derived impacts on climate change, policy makers at both the United States federal and state level have introduced legislation and proposed new regulations that are designed to quantify and limit the emission of greenhouse gases through inventories and limitations on greenhouse gas emissions. Legislative initiatives to date have focused on the development of cap and trade programs. These programs generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. As a result of a gradually declining cap, the number of government-issued allowances and allowances available for trade would be reduced each year until the overall goal of greenhouse gas emission reductions is achieved.

Because no final legislation or regulations limiting greenhouse gas emissions have been enacted at this time, it is not possible to estimate the costs or operational impacts we could experience to comply with new legislative or regulatory developments. Although we do not anticipate that we would be impacted to any greater degree than other similar oil and gas companies, a stringent greenhouse gas control program could increase our cost of doing business and reduce demand for the oil and natural gas that we sell. However, to the extent that any particular greenhouse gas program directly or indirectly encourages the use of natural gas, demand for the natural gas we sell could increase.

The Kyoto Protocol was adopted by numerous countries in 1997 and implemented in 2005. The Protocol requires reductions of certain emissions of greenhouse gases. Although the United States has not ratified the Protocol, certain countries in which we operate have. Canada ratified the Protocol in April 2007 and released its Regulatory Framework for Air Emissions. The Canadian framework is a plan to implement mandatory reductions in greenhouse gas emissions. The mandatory reductions on greenhouse gas emissions will create additional costs for the Canadian oil and gas industry, including us. Certain provinces in Canada also have implemented or are currently implementing legislation and regulations to report and reduce greenhouse gas emissions, which also will carry a cost associated with compliance. Presently, it is not possible to accurately estimate the costs we could incur to comply with any laws or regulations developed to achieve emissions reductions in Canada or elsewhere, but such expenditures could be substantial.

In 2006, we established our Corporate Climate Change Position and Strategy. Key components of the strategy include initiation of energy efficiency measures, tracking emerging climate change legislation and publication of a corporate greenhouse gas emission inventory. We last published our emission inventory on January 2008. We will publish another emission inventory on or before March 31, 2011 to comply with a reporting mandate issued by the United States Environmental Protection Agency. Additionally, we continue to explore energy efficiency measures and greenhouse emission reduction opportunities. We also continue to monitor legislative and regulatory climate change developments, such as the proposals described above.

Employees

As of December 31, 2009, we had approximately 5,400 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.

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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 our corporate governance (including our Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer), and documents we file or furnish 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. If any of the following risk factors should occur, our profitability, financial condition or liquidity could be materially impacted. As a result, holders of our securities could lose part or all of their investment in Devon.

Oil, Gas and NGL Prices are Volatile

Our financial results are highly dependent on the prices of and demand for oil, gas and NGLs. A significant downward movement of the prices for these commodities could have a material adverse effect on our revenues, operating cash flows and profitability. Such a downward price movement could also have a material adverse effect on our estimated proved reserves, the carrying value of our oil and gas properties, the level of planned drilling activities 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, gas and NGLs;
- conservation efforts;
- OPEC production levels;
- weather;
- regional pricing differentials;
- 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, gas and NGLs;
- the price and availability of alternative fuels;
- the overall economic environment; and
- governmental regulations and taxes.

Estimates of Oil, 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 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.

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Additional discussion of our policies and internal controls related to estimating and recording reserves is described in Item 2. Properties Preparation of Reserves Estimates and Reserves Audits.

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

The production rates from oil and gas properties generally decline 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 transportation methods;
- environmental hazards or liabilities; and
- shortages or delays in the availability of services or 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. Typically, during times of high or rising commodity prices, drilling and operating costs will also increase. Higher prices will also generally increase the costs of properties available for acquisition. Certain of our competitors have financial and other resources substantially

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larger than ours. They also may have established strategic long-term positions and relationships in areas 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 gas production, such as changing worldwide price and production levels, 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 and China. As noted earlier in this report, we are in the process of divesting our operations outside North America. However, until we cease operating in these locations, we face political and economic risks and other uncertainties in these areas that are more prevalent than what exist 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 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 our 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.

Public Policy, Which Includes Laws, Rules and Regulations, Can Change

Our operations are subject to federal laws, rules and regulations in the United States, Canada and the other countries in which we operate. In addition, we are also subject to the laws and regulations of various states, provinces, tribal and local governments. Pursuant to public policy changes, 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 public policy have affected, and at times in the future could affect, our 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 public policy 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, lessee or operator of oil and gas properties, we are subject to various federal, state, provincial, tribal, 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 public policy 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, 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 insurance marketplace following hurricanes in the Gulf of Mexico in recent years, we currently do not have coverage for any damage that may be caused by future named windstorms in the Gulf of Mexico.

Certain of Our Investments Are Subject To Risks That May Affect Their Liquidity and Value

To maximize earnings on available cash balances, we periodically invest in securities that we consider to be short-term in nature and generally available for short-term liquidity needs. During 2007, we purchased asset-backed securities that have an auction rate reset feature (auction rate securities). Our auction rate securities generally have contractual maturities of more than 20 years. However, the underlying interest rates on our securities are scheduled to reset every seven to 28 days. Therefore, when we bought these securities, they were generally priced and subsequently traded as short-term investments because of the interest rate reset feature. At December 31, 2009, our auction rate securities totaled $115 million.

Since February 8, 2008, we have experienced difficulty selling our securities due to the failure of the auction mechanism, which provided liquidity to these securities. An auction failure means that the parties wishing to sell securities could not do so. The securities for which auctions have failed will continue to accrue interest and be auctioned every seven to 28 days until the auction succeeds, the issuer calls the securities or the securities mature. Due to continued auction failures throughout 2009, we consider these investments to be long-term in nature and generally not available for short-term liquidity needs.

Our auction rate securities are rated AAA the highest rating by one or more rating agencies and are collateralized by student loans that are substantially guaranteed by the United States government. These investments are subject to general credit, liquidity, market and interest rate risks, which may be exacerbated by problems in the global credit markets, including but not limited to, U.S. subprime mortgage defaults and writedowns by major financial institutions due to deteriorating values of their asset portfolios. These and other related factors have affected various sectors of the financial markets and caused credit and liquidity issues. If issuers are unable to successfully close future auctions and their credit ratings deteriorate, our ability to liquidate these securities and fully recover the carrying value of our investment in the near term may be limited. Under such circumstances, we may record an impairment charge on these investments in the future.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 2. *Properties*

Property Overview

Our oil and gas operations are concentrated in various North American onshore areas in the United States and Canada. We also have offshore operations that are situated principally in the Gulf of Mexico and regions located offshore Azerbaijan, Brazil and China. As previously mentioned, we are in the process of divesting our offshore assets. Our properties consist of interests in developed and undeveloped oil and gas leases and mineral acreage in these regions. These interests entitle us to drill for and produce oil, 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 3,100 miles of pipeline, two natural gas processing plants with 750 MMcf per day of total capacity, and a 15 MBbls per day NGL fractionator. To support our continued development and growing production in the Woodford Shale, located in southeastern Oklahoma, we constructed the Northridge natural gas processing plant in 2008. The Northridge plant has a capacity of 200 MMcf per day.

Our midstream assets also include the Access Pipeline transportation system in Canada. This 220-mile dual pipeline system extends from our Jackfish operations in northern Alberta to a 350 MBbls storage terminal near Edmonton. The dual pipeline system allows us to blend the Jackfish heavy oil production with condensate and transport the combined product to the Edmonton crude oil market for sale. We have a 50% ownership interest in the Access Pipeline.

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The following sections provide additional details of our oil and gas properties, including information about proved reserves, production, wells, acreage and drilling activities.

Property Profiles

The locations of our key North American Onshore properties are presented on the following map.

The following table presents proved reserve information for our key properties as of December 31, 2009, along with their production volumes for the year 2009. Additional summary profile information for our key properties is provided following the table. Our key properties include those that currently have significant proved reserves or production. These key properties also include properties that do not have current significant levels of proved reserves or production, but are expected be the source of future significant growth in proved reserves and production.

	Proved Reserves (MMBoe)(1)	Proved Reserves %(2)	Production (MMBoe)(1)	Production %(2)
U.S. Onshore				
Barnett Shale	1,027	37.6%	69	29.6%
Carthage	182	6.7%	14	6.4%
Permian Basin, Texas	127	4.6%	9	3.9%
Washakie	93	3.4%	7	3.0%
Cana-Woodford Shale	73	2.7%	3	1.0%
Arkoma-Woodford Shale	47	1.7%	5	2.0%
Groesbeck	43	1.6%	6	2.6%
Haynesville Shale	6	0.2%	1	0.3%
Other U.S. Onshore	280	10.2%	40	17.1%
Total U.S. Onshore	**1,878**	**68.7%**	**154**	**65.9%**
U.S. Offshore	**92**	**3.4%**	**13**	**5.7%**
Total U.S.	**1,970**	**72.1%**	**167**	**71.6%**
Canada				
Jackfish	403	14.7%	8	3.4%
Northwest	117	4.3%	16	7.3%
Lloydminster	81	3.0%	16	6.7%
Deep Basin	59	2.2%	12	5.0%
Horn River Basin	2			
Other Canada	101	3.7%	14	6.0%
Total Canada	**763**	**27.9%**	**66**	**28.4%**
North America	**2,733**	**100.0%**	**233**	**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 gas and oil, which rate is not necessarily indicative of the relationship of gas and 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.

U.S. Onshore

Barnett Shale The Barnett Shale, located in north Texas, is our largest property both in terms of production and proved reserves. Our leases include approximately 663,000 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 NGLs. We have an average working interest of 89%. We drilled 336 gross wells in 2009 and plan to drill approximately 370 gross wells in 2010.

Carthage The Carthage area in east Texas includes primarily Harrison, Marion, Panola and Shelby counties. Our average working interest is about 86% and we hold approximately 218,000 net acres. Our Carthage area wells produce primarily natural gas and NGLs from conventional reservoirs. We drilled 39 gross wells in 2009 and plan to drill approximately 30 gross wells in 2010.

Permian Basin, Texas Our oil and gas properties in the Permian Basin of west Texas comprise approximately 850,000 net acres located across several counties in west Texas. These properties produce both oil and gas from conventional reservoirs. Our average working interest in these properties is about 40%. In 2009, we drilled 80 gross wells and plan to drill approximately 220 gross wells in 2010.

Washakie Our Washakie area leases are concentrated in Carbon and Sweetwater counties in southern Wyoming. Our average working interest is about 76% and we hold about 157,000 net acres in the area. The Washakie wells produce primarily natural gas from conventional reservoirs. In 2009, we drilled 94 gross wells and plan to drill approximately 115 gross wells in 2010.

Cana-Woodford Shale The Cana-Woodford Shale is located in Canadian, Blaine and Caddo counties in western Oklahoma. Our average working interest is approximately 46% and we hold approximately 117,000 net acres. Our Cana-Woodford Shale properties produce natural gas and NGLs from a non-conventional reservoir. We drilled 47 gross wells in 2009 and plan to drill approximately 85 gross wells in 2010. To support our growing production in the Cana-Woodford Shale, we are building a 200 MMcf per day natural gas processing facility. We expect to complete this facility in early 2011.

Arkoma-Woodford Shale Our Arkoma-Woodford Shale properties in southeastern Oklahoma produce natural gas and NGLs from a non-conventional reservoir. Our 58,000 net acres are concentrated in Coal and Hughes counties, and we have an average working interest of about 32%. In 2009, we drilled 61 gross wells in this area and plan to drill approximately 85 gross wells in 2010.

Groesbeck The Groesbeck area of east Texas includes portions of Freestone, Leon, Limestone and Robertson counties. Our average working interest is approximately 72% and we hold about 132,000 net acres of land. The Groesbeck wells produce primarily natural gas from conventional reservoirs. In 2009, we drilled 13 gross wells and plan to drill approximately 10 gross wells in 2010.

Haynesville Shale Our Haynesville Shale acreage spans across east Texas and north Louisiana with an average working interest of 92%. To date, our drilling activity has been focused on de-risking the 157,000 acres located in Panola, Shelby and San Augustine counties in east Texas. We drilled 8 gross wells in 2009 and plan to drill approximately 30 gross wells in 2010.

Canada

Jackfish Jackfish is our 100%-owned thermal heavy oil project in the non-conventional oil sands of east central Alberta. We are employing steam-assisted gravity drainage at Jackfish. In late 2009, Jackfish s gross production reached 33.7 MBbls of oil per day. Gross peak production is expected to be 35 MBbls per day with a flat production profile for greater than 20 years. We are currently constructing the second phase of Jackfish and evaluating the potential for a third phase. The second and third phases of Jackfish are each expected to also eventually produce 35 MBbls per day of heavy oil production.

Northwest The Northwest region includes acreage within west central Alberta and northeast British Columbia. We hold approximately 1.9 million net acres in the region, which produces primarily natural gas and NGLs from conventional reservoirs. Our average working interest in the area is approximately 73%. In 2009, we drilled 36 gross wells and plan to drill approximately 55 gross wells in 2010.

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 2.5 million net acres and have an 89% average working interest in our Lloydminster properties. In 2009, we drilled 239 gross wells and plan to drill approximately 140 gross wells in 2010.

Deep Basin Our properties in Canada s Deep Basin include portions of west central Alberta and east central British Columbia. We hold approximately 570,000 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 Deep Basin is 45%. In 2009, we drilled 30 gross wells and plan to drill approximately 35 gross wells in 2010.

Horn River Basin The Horn River Basin, located in northeast British Columbia, is a non-conventional reservoir targeting the Devonian Shale. Our leases include approximately 170,000 net acres with a 100% working interest. We drilled 2 gross wells in 2009. During 2010, we plan to drill 11 gross wells, consisting of 7 horizontal wells and 4 vertical stratigraphic-test wells.

Preparation of Reserves Estimates and Reserves Audits

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from known reservoirs under existing economic conditions, operating methods and government regulations. To be considered proved, oil and gas reserves must be economically producible before contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Also, the project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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. Our policies assign responsibilities for compliance in reserves bookings to our Reserve Evaluation Group (the Group). These same policies also require that reserve estimates be made by professionally qualified reserves estimators (Qualified Estimators), as defined by the Society of Petroleum Engineers standards.

The Group, which is led by Devon s Director of Reserves and Economics, is responsible for the internal review and certification of reserves estimates. We ensure the Group s Director and key members of the Group have appropriate technical qualifications to oversee the preparation of reserves estimates. Such qualifications include any or all of the following:

- an undergraduate degree in petroleum engineering from an accredited university, or equivalent;
- a petroleum engineering license, or similar certification;
- memberships in oil and gas industry or trade groups; and
- relevant experience estimating reserves.

The current Director of the Group and the Group s key members all have the qualifications listed above. Additionally, the Group reports independently of any of our operating divisions. The Group s Director reports to our Senior Vice President of Strategic Development, who reports to our President. No portion of the Group s compensation is directly 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. The Group also ensures our Qualified Estimators obtain continuing education related to the fundamentals of SEC proved reserves assignments.

The Group also oversees audits and reserves estimates performed by third-party consulting firms. During 2009, we engaged three such firms to both prepare and audit a significant portion of our proved reserves. Ryder Scott Company, L.P. prepared the 2009 reserve estimates for all of our offshore Gulf of Mexico properties and for 99% of our International proved reserves. LaRoche Petroleum Consultants, Ltd. audited the 2009 reserve estimates for 93% of our domestic onshore properties. AJM Petroleum Consultants audited 91% of our Canadian reserves.

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Set forth below is a summary of the North American reserves that were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2009, 2008 and 2007.

	2009		2008		2007	
	Prepared	Audited	Prepared	Audited	Prepared	Audited
U.S. Onshore		93%		92%		88%
U.S. Offshore	100%		100%		100%	
Total U.S.	5%	89%	5%	87%	6%	82%
Canada		91%		78%	34%	51%
Total North America	3%	89%	4%	85%	15%	73%

Prepared reserves are those quantities of reserves that were prepared by an independent petroleum consultant. Audited reserves are those quantities of reserves that 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 conducting these internal and external reviews, we also have a Reserves Committee that consists of three independent members of our Board of Directors. Although we are not required to have a Reserves Committee, we established ours in 2004 to provide additional oversight of our reserves estimation and certification process. The Reserves Committee was designed to assist the Board of Directors with its duties and responsibilities in evaluating and reporting our proved reserves, much like our Audit Committee assists the Board of Directors in supervising our audit and financial reporting requirements. Besides being independent, the members of our Reserves Committee also have educational backgrounds in geology or petroleum engineering, as well as experience relevant to the reserves estimation process.

The Reserves Committee meets at least 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 responsibilities of the Reserves Committee include the following:

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

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Proved Oil, Natural Gas and NGL Reserves

The following table presents our estimated proved reserves by continent and for each significant country as of December 31, 2009. These estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 22 to our consolidated financial statements included in this report.

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Proved Reserves				
U.S. Onshore	139	8,127	385	1,878
U.S. Offshore	33	342	2	92
Total U.S.	172	8,469	387	1,970
Canada	514	1,288	34	763
Total North America	686	9,757	421	2,733
Proved Developed Reserves				
U.S. Onshore	119	6,447	293	1,486
U.S. Offshore	21	185	1	53
Total U.S.	140	6,632	294	1,539
Canada	149	1,213	32	383
Total North America	289	7,845	326	1,922
Proved Undeveloped Reserves				
U.S. Onshore	20	1,680	92	392
U.S. Offshore	12	157	1	39
Total U.S.	32	1,837	93	431
Canada	365	75	2	380
Total North America	397	1,912	95	811

(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 gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

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 2009 except in filings with the SEC and 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.

Proved Developed Reserves

As presented in the previous table, we had 1,922 MMBoe of proved developed reserves at December 31, 2009. 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, 2009.

	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Proved Developed Producing Reserves				
U.S. Onshore	111	5,859	265	1,354
U.S. Offshore	12	137	1	35
Total U.S.	123	5,996	266	1,389
Canada	137	1,075	28	344
Total North America	260	7,071	294	1,733
Proved Developed Non-Producing Reserves				
U.S. Onshore	8	588	28	132
U.S. Offshore	9	48		18
Total U.S.	17	636	28	150
Canada	12	138	4	39
Total North America	29	774	32	189

(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 gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

Proved Undeveloped Reserves

The following table presents the changes in our total proved undeveloped reserves during 2009 (in MMBoe).

Proved undeveloped reserves as of December 31, 2008	424
Revisions due to prices	174
Revisions other than price	(22)
Extensions and discoveries	316
Conversion to proved developed reserves	(81)
Proved undeveloped reserves as of December 31, 2009	811

During 2009, our proved undeveloped reserves increased 91%. A large contributor to the increase was our 2009 drilling activities, which increased our proved undeveloped reserves 316 MMBoe. Also as a result of 2009 drilling activities, we converted 81 MMBoe, or 19%, of the 2008 proved undeveloped reserves to proved developed reserves.

Our proved undeveloped reserves at the end of 2009 largely relate to our operations at Jackfish and the Barnett Shale. Additionally, the 2009 positive revisions due to prices largely related to Jackfish. At the end of 2008, none of our Jackfish reserves were classified as proved due to low oil prices. However, as oil prices rebounded during 2009, our Jackfish reserves, including the reserves that were undeveloped at the end of 2008, once again became economic and were classified as proved at the end of 2009. The positive revision related to Jackfish reserves was partially offset by decreases in proved undeveloped gas reserves related to certain of our North American Onshore properties.

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At the end of 2009, approximately 1% of our proved reserves had been classified as proved undeveloped for more than five years. The majority of such reserves relate to our deepwater Gulf of Mexico operations where sanctioned development projects often take longer than five years to complete.

Proved Reserves Cash Flows

The following table presents estimated cash flow information related to our December 31, 2009 estimated proved reserves. Similar to reserves, the cash flow estimates correspond with the method used in presenting the Supplemental Information on Oil and Gas Operations in Note 22 to our consolidated financial statements included in this report.

	Total Proved Reserves	Proved Developed Reserves	Proved Undeveloped Reserves
		(In millions)	
Pre-Tax Future Net Revenue(1)			
United States	$ 15,573	$ 13,381	$ 2,192
Canada	14,463	6,127	8,336
Total North America	$ 30,036	$ 19,508	$ 10,528
Pre-Tax 10% Present Value(1)			
United States	$ 7,630	$ 7,452	$ 178
Canada	7,243	4,210	3,033
Total North America	$ 14,873	$ 11,662	$ 3,211
Standardized Measure of Discounted Future Net Cash Flows(1)(2)			
United States	$ 5,880		
Canada	5,523		
Total North America	$ 11,403		

(1) 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 depreciation, depletion and amortization, or to non-property related expenses such as debt service and income tax expense.

Future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to December 31, 2009. These prices were not changed except where different prices were fixed and determinable from applicable contracts. These assumptions yielded average prices over the life of our properties of $47.80 per Bbl of oil, $3.12 per Mcf of gas and $22.78 per Bbl of NGLs. Costs included in future net revenues are determined in a similar manner. 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, 2009. 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.

The present value of after-tax future net revenues discounted at 10% per annum (standardized measure) was $11.4 billion at the end of 2009. Included as part of standardized measure were discounted future income taxes of $3.4 billion. Excluding these taxes, the present value of our pre-tax future net revenue (pre-tax 10% present value) was $14.8 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,

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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.

(2) See Note 22 to the consolidated financial statements included in Item 8. Financial Statements and Supplementary Data.

Production, Production Prices and Production Costs

The following tables present our production and average sales prices by continent and for each significant field and country for the past three years.

	Year Ended December 31, 2009			
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Production				
Barnett Shale		331	13	69
Other United States fields	17	412	13	98
Total United States	17	743	26	167
Jackfish	8			8
Other Canada fields	17	223	4	58
Total Canada	25	223	4	66
Total North America	42	966	30	233

	Oil (Per Bbl)	Natural Gas (Per Mcf)	Natural Gas Liquids (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 58.78	$ 2.99	$ 22.36	$ 19.08
Total United States	$ 57.56	$ 3.20	$ 23.51	$ 23.71
Jackfish	$ 41.07			$ 41.07
Total Canada	$ 47.35	$ 3.66	$ 33.09	$ 32.29
Total North America	$ 51.39	$ 3.31	$ 24.71	$ 26.15

	Year Ended December 31, 2008			
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)

Production				
Barnett Shale		321	12	66
Other United States fields	17	405	12	96
Total United States	17	726	24	162
Jackfish	4			4
Other Canada fields	18	212	4	57
Total Canada	22	212	4	61
Total North America	39	938	28	223

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	Year Ended December 31, 2008			
	Oil (Per Bbl)	Natural Gas (Per Mcf)	Natural Gas Liquids (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 97.23	$ 7.38	$ 39.34	$ 43.71
Total United States	$ 98.83	$ 7.59	$ 41.21	$ 50.55
Jackfish	$ 50.67			$ 50.67
Total Canada	$ 71.04	$ 8.17	$ 61.45	$ 57.65
Total North America	$ 83.35	$ 7.73	$ 44.08	$ 52.49

	Year Ended December 31, 2007			
	Oil (MMBbls)	Natural Gas (Bcf)	Natural Gas Liquids (MMBbls)	Total(1) (MMBoe)
Production				
Barnett Shale		238	10	50
Other United States fields	19	397	12	96
Total United States	19	635	22	146
Total Canada	16	227	4	58
Total North America	35	862	26	204

	Oil (Per Bbl)	Natural Gas (Per Mcf)	Natural Gas Liquids (Per Bbl)	Combined(1) (Per Boe)
Production Prices				
Barnett Shale	$ 70.61	$ 5.63	$ 34.68	$ 34.28
Total United States	$ 69.23	$ 5.87	$ 36.11	$ 39.77
Total Canada	$ 49.80	$ 6.24	$ 46.07	$ 41.51
Total North America	$ 60.30	$ 5.97	$ 37.76	$ 40.26

(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 gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

The following table presents our production cost per Boe by continent and for each significant field and country for the past three years. Production costs do not include ad valorem or severance taxes.

	Year Ended December 31,		
	2009	2008	2007
Barnett Shale	$ 3.96	$ 4.34	$ 3.85
Total United States	$ 5.97	$ 6.62	$ 6.19
Jackfish	$ 12.75	$ 28.93	
Total Canada	$ 10.15	$ 12.74	$ 10.80
Total North America	$ 7.16	$ 8.29	$ 7.50

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Drilling Activities and Results

The following tables summarize our development and exploratory drilling results for the past three years.

	Year Ended December 31, 2009					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	506.5	3.0	6.8	1.5	513.3	4.5
U.S. Offshore	1.5	0.8		0.5	1.5	1.3
Total U.S.	508.0	3.8	6.8	2.0	514.8	5.8
Canada	307.2		28.2		335.4	
Total North America	815.2	3.8	35.0	2.0	850.2	5.8

	Year Ended December 31, 2008					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	1,024.0	17.5	12.8	2.0	1,036.8	19.5
U.S. Offshore	9.0	1.0	0.8	1.8	9.8	2.8
Total U.S.	1,033.0	18.5	13.6	3.8	1,046.6	22.3
Canada	528.9	3.2	50.1	3.3	579.0	6.5
Total North America	1,561.9	21.7	63.7	7.1	1,625.6	28.8

	Year Ended December 31, 2007					
	Development Wells(1)		Exploratory Wells(1)		Total Wells(1)	
	Productive	Dry	Productive	Dry	Productive	Dry
U.S. Onshore	974.4	21.1	10.1	4.0	984.5	25.1
U.S. Offshore	3.7		1.5	0.2	5.2	0.2
Total U.S.	978.1	21.1	11.6	4.2	989.7	25.3
Canada	531.2		83.3	1.5	614.5	1.5
Total North America	1,509.3	21.1	94.9	5.7	1,604.2	26.8

(1) These well counts represent net wells completed during each year. Net wells are gross wells multiplied by our fractional working interests on the well.

The following table presents the results, as of February 1, 2010, of our wells that were in progress as of December 31, 2009.

	Productive		**Dry**		**Still in Progress**		**Total**	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
U.S. Onshore	13	9.1			46	33.2	59	42.3
U.S. Offshore					3	1.5	3	1.5
Total U.S.	13	9.1			49	34.7	62	43.8
Canada	18	13.7			3	2.5	21	16.2
Total North America	31	22.8			52	37.2	83	60.0

(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 on the well.

Well Statistics

The following table sets forth our producing wells as of December 31, 2009.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
U.S. Onshore	8,301	2,901	19,792	13,442	28,093	16,343
U.S. Offshore	359	284	204	138	563	422
Total U.S.	8,660	3,185	19,996	13,580	28,656	16,765
Canada	4,830	3,661	5,560	3,241	10,390	6,902
Total North America	13,490	6,846	25,556	16,821	39,046	23,667

(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 on the well.

Acreage Statistics

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2009.

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
			(In thousands)			
U.S. Onshore	3,357	2,268	6,064	3,318	9,421	5,586
U.S. Offshore	258	139	1,809	1,029	2,067	1,168
Total U.S.	3,615	2,407	7,873	4,347	11,488	6,754
Canada	3,630	2,253	7,688	5,088	11,318	7,341
Total North America	7,245	4,660	15,561	9,435	22,806	14,095

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

(2) Net acres are gross acres multiplied by our fractional working interests on the acreage.

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 24,221 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.

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.

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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, which generally include 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*

We are involved in various routine legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there were no 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 2009.

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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, 2010, there were 13,740 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 during 2009 and 2008. Also, included are the quarterly dividends per share paid during 2009 and 2008. 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.

	Price Range of Common Stock		Dividends
	High	Low	Per Share
2009:			
Quarter Ended March 31, 2009	$ 73.11	$ 38.55	$ 0.16
Quarter Ended June 30, 2009	$ 67.40	$ 43.35	$ 0.16
Quarter Ended September 30, 2009	$ 72.91	$ 48.74	$ 0.16
Quarter Ended December 31, 2009	$ 75.05	$ 62.60	$ 0.16
2008:			
Quarter Ended March 31, 2008	$ 108.13	$ 74.56	$ 0.16
Quarter Ended June 30, 2008	$ 127.16	$ 101.31	$ 0.16
Quarter Ended September 30, 2008	$ 127.43	$ 82.10	$ 0.16
Quarter Ended December 31, 2008	$ 91.69	$ 54.40	$ 0.16

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Performance Graph

The following performance graph compares the yearly percentage change in the cumulative total shareholder return on Devon s common stock with the cumulative total returns of the Standard & Poor s 500 index (the S&P 500 Index) and the group of companies included in the Crude Petroleum and Natural Gas Standard Industrial Classification code (the SIC Code). The graph was prepared based on the following assumptions:

$100 was invested on December 31, 2004 in Devon s common stock, the S&P 500 Index and the SIC Code, and

Dividends have been reinvested subsequent to the initial investment.

Comparison of 5-Year Cumulative Total Return

The graph and related information shall not be deemed soliciting material or to be filed with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

Issuer Purchases of Equity Securities

During 2009, we had two programs in effect in which our Board of Directors had authorized the repurchase of up to 54.8 million shares of our common stock. We did not repurchase any shares under these programs in 2009. These plans expired on December 31, 2009.

New York Stock Exchange Certifications

This Form 10-K includes as exhibits the certifications of our Chief Executive Officer and Chief Financial Officer, or persons performing similar functions, required to be filed with the SEC pursuant to Section 302 of the Sarbanes Oxley Act of 2002. We have also filed with the New York Stock Exchange the 2009 annual certification of our Chief Executive Officer confirming that we have complied with the New York Stock Exchange corporate governance listing standards.

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

The following selected financial information (not covered by the report of our 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,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In millions, except per share data, ratios, prices and per Boe amounts)				
Operating Results					
Revenues	$ 8,015	$ 13,858	$ 9,975	$ 9,143	$ 9,630
Total expenses and other income, net(1)	12,541	18,018	6,648	5,957	5,477
(Loss) earnings from continuing operations before income taxes	(4,526)	(4,160)	3,327	3,186	4,153
Total income tax (benefit) expense	(1,773)	(1,121)	842	870	1,413
(Loss) earnings from continuing operations	(2,753)	(3,039)	2,485	2,316	2,740
Earnings from discontinued operations(1)	274	891	1,121	530	190
Net (loss) earnings	$ (2,479)	$ (2,148)	$ 3,606	$ 2,846	$ 2,930
Net (loss) earnings applicable to common stockholders	$ (2,479)	$ (2,153)	$ 3,596	$ 2,836	$ 2,920
Basic net (loss) earnings per share:					
(Loss) earnings from continuing operations	$ (6.20)	$ (6.86)	$ 5.56	$ 5.22	$ 5.96
Earnings from discontinued operations	0.62	2.01	2.52	1.20	0.42
Net (loss) earnings	$ (5.58)	$ (4.85)	$ 8.08	$ 6.42	$ 6.38
Diluted net (loss) earnings per share:					
(Loss) earnings from continuing operations	$ (6.20)	$ (6.86)	$ 5.50	$ 5.15	$ 5.86
Earnings from discontinued operations	0.62	2.01	2.50	1.19	0.40
Net (loss) earnings	$ (5.58)	$ (4.85)	$ 8.00	$ 6.34	$ 6.26
Cash dividends per common share	$ 0.64	$ 0.64	$ 0.56	$ 0.45	$ 0.30
Ratio of earnings to fixed charges(1)(2)	N/A	N/A	6.97	7.11	7.67
Ratio of earnings to combined fixed charges and preferred stock dividends(1)(2)	N/A	N/A	6.78	6.91	7.49
Cash Flow Data					
Net cash provided by operating activities	$ 4,737	$ 9,408	$ 6,651	$ 5,993	$ 5,612
Net cash used in investing activities	$ (5,354)	$ (6,873)	$ (5,714)	$ (7,449)	$ (1,652)
	$ 1,201	$ (3,408)	$ (371)	$ 593	$ (3,543)

Net cash provided by (used in) financing activities										
Production, Price and Other Data(3)										
Production:										
Oil (MMBbls)		42		39		35		32		38
Gas (Bcf)		966		938		862		807		816
NGLs (MMBbls)		30		28		26		23		24
Total (MMBoe)(4)		233		223		204		190		198
Realized prices without hedges:										
Oil (per Bbl)	$	51.39	$	83.35	$	60.30	$	56.18	$	47.90
Gas (per Mcf)	$	3.31	$	7.73	$	5.97	$	6.03	$	7.08
NGLs (per Bbl)	$	24.71	$	44.08	$	37.76	$	32.10	$	29.05
Combined (per Boe)(4)	$	26.15	$	52.49	$	40.26	$	39.09	$	41.96
Lease operating expenses per Boe(4)	$	7.16	$	8.29	$	7.50	$	6.48	$	5.60
Depreciation, depletion and amortization of oil and gas properties per Boe(4)	$	7.86	$	13.20	$	11.81	$	10.28	$	8.62

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	December 31,				
	2009	2008	2007	2006	2005
			(In millions)		
Balance Sheet Data					
Total assets(1)	$ 29,686	$ 31,908	$ 41,456	$ 35,063	$ 30,273
Long-term debt	$ 5,847	$ 5,661	$ 6,924	$ 5,568	$ 5,957
Stockholders equity	$ 15,570	$ 17,060	$ 22,006	$ 17,442	$ 14,862

(1) During 2009 and 2008, we recorded noncash reductions of carrying value of oil and gas properties totaling $6.4 billion ($4.1 billion after income taxes) and $9.9 billion ($6.7 billion after income taxes), respectively, related to our continuing operations as discussed in Note 15 of the consolidated financial statements. During 2009, 2008 and 2007 we recorded noncash reductions of carrying value of oil and gas properties totaling $108 million ($105 million after taxes), $494 million ($465 million after taxes) and $68 million ($13 million after taxes) related to our discontinued operations as discussed in Note 18 of the consolidated financial statements.

(2) 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 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 preferred stock that was outstanding until June 2008.

For 2009, earnings from continuing operations were inadequate to cover fixed charges by $4.6 billion. For 2008, earnings from continuing operations were inadequate to cover fixed charges and combined fixed charges and preferred stock dividends by $4.2 billion. These earnings relationships were primarily the result of the noncash reductions of the carrying values of certain oil and gas properties referred to above.

(3) The amounts presented under Production, Price and Other Data exclude the amounts related to our discontinued international operations. The price data presented excludes the effects of unrealized and realized gains and losses from our oil and gas derivative financial instruments.

(4) 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 gas and oil, which rate is not necessarily indicative of the relationship of gas and oil 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 and should be reviewed in conjunction with our Selected Financial Data and Financial Statements and Supplementary Data. Our discussion and analysis relates to the following subjects:

Overview of Business

Overview of Business

Devon is one of North America s leading independent oil and gas exploration and production companies. Our operations are focused in the United States and Canada. We also own natural gas pipelines and treatment facilities in many of our producing areas, making us one of North America s larger processors of natural gas liquids.

As an enterprise, we strive to optimize value for our shareholders by growing reserves, production, earnings and cash flows, all on a per share basis. We accomplish this by replenishing our reserves and production and managing other key operational elements that drive our success. These items are discussed more fully below.

Reserves and production growth Our financial condition and profitability are significantly affected by the amount of proved reserves we own. Oil and gas properties are our most significant assets, and the reserves that relate to such properties are key to our future success. To increase our proved reserves, we must replace quantities produced with additional reserves from successful exploration and development activities or property acquisitions. Additionally, our profitability and operating cash flows are largely dependent on the amount of oil, gas and NGLs we produce. 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 and develop 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. As a result, we have historically deployed virtually all our available cash flow into capital projects. Therefore, maintaining a disciplined approach to investing in capital projects is important to our profitability and financial condition. 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. The inverse is also true.

Approximately two-thirds of our planned 2010 investment in capital projects is dedicated to a foundation of low-risk projects in our North American Onshore properties. The remainder of our capital has been identified for longer-term projects primarily in new unconventional natural gas plays in several U.S. Onshore regions, as well as offshore activities in the Gulf of Mexico. 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. The timing of closing the planned sales of our Gulf of Mexico properties will impact exactly how much of our 2010 capital is used on our Gulf of Mexico assets.

High margin assets Like many investors, we seek to invest our capital resources into projects where we can generate the highest risk-adjusted investment returns. One factor that can have a significant impact on such returns is our drilling success rates. Combined with appropriate revenue and cost-management strategies, high drilling success rates are important to generating competitive returns on our capital investment. During 2009, we drilled 1,135 wells and 99% of those were successful. The success rate is similar to our drilling achievements in recent years, demonstrating a proven track record of success. By accomplishing high drilling success rates, we provide an inventory of reserves growth and a platform of opportunities on our undrilled acreage that can be profitably developed.

Reserves and production balance As evidenced by history, commodity prices are inherently volatile. In addition, oil and gas prices often diverge due to a variety of circumstances. Consequently, we value a balance of reserves and production between gas and liquids that can add stability to our revenue stream when either commodity price is under pressure. Our production mix in 2009 was approximately 70% gas and 30% oil and NGLs such as propane, butane and ethane. Our year-end reserves were approximately 60% gas and 40% liquids. With planned future growth in oil from our Jackfish and other projects, combined with an inventory of shale natural gas plays, we expect to maintain this balance in the future.

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 by significant changes in commodity prices. Our base North American production is focused in core areas of our operations where we can achieve economies of scale to help manage our operating costs.

Marketing and midstream performance improvement We enhance the value of our oil and gas operations with our marketing and midstream business. By efficiently gathering and processing oil, gas and NGL production, our midstream operations contribute to our strategies to grow reserves and production and manage expenditures. Additionally, by effectively marketing our production, we maximize the prices received for our oil, gas and NGL production in relation to market prices. This is important because our profitability is highly dependent on market prices. These prices 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, we utilize financial hedging arrangements and fixed-price physical delivery contracts. As of February 15, 2010, approximately 53% of our 2010 gas production is associated with financial price swaps and collars. Additionally, approximately 65% of our 2010 oil production is associated with financial price collars.

Financial flexibility preservation As mentioned, commodity prices have been and will continue to be volatile and will continue to impact our profitability and cash flow. We understand this fact and manage our debt levels accordingly to preserve our liquidity and financial flexibility. We generally operate within the cash flow generated by our operations. However, during periods of low commodity prices, we may use our balance sheet strength to access debt or equity markets, allowing us to preserve our business and maintain momentum until markets recover. When prices improve, we can utilize excess operating cash flow to repay debt and invest in our activities that not only maintain but also increase value per share.

Overview of 2009 Results

2009 was a pivotal year for us as we began repositioning Devon to focus entirely on our high-return, North American Onshore natural gas and oil portfolio. We grew North American Onshore production more than six percent in 2009 and replaced more than twice our production with the drill bit at very attractive costs. The performance of these assets is reflected in our earnings, which steadily increased over the last three quarters of 2009.

However, our full year 2009 results were significantly impacted by the downward pressure in oil and natural gas prices that began in the last half of 2008 and continued throughout 2009. The Henry Hub natural gas index average for 2009 was 56% lower than 2008. Although crude prices have improved since the end of 2008, the 2009 West Texas Intermediate oil index average was 38% lower than 2008.

The lower oil and gas prices significantly impacted our first quarter 2009 earnings, which in turn impacted our full year earnings. During 2009, we incurred a net loss of $2.5 billion, or $5.58 per diluted share. These amounts are the result of a noncash impairment of our oil and gas properties that was recognized in the first quarter of 2009 and totaled $4.2 billion, net of income taxes. Substantially all of this noncash charge was the result of the drop in natural gas prices during the first quarter of 2009.

Key measures of our performance for 2009, as well as certain operational developments, are summarized below:

Production grew 4% over 2008, to 233 million Boe.

The combined realized price for oil, gas and NGLs per Boe decreased 50% to $26.15.

Oil and gas hedges generated net gains of $384 million in 2009, including cash receipts of $505 million.

Marketing and midstream operating profit decreased 25% to $512 million.

Per unit lease operating costs decreased 14% to $7.16 per Boe.

Operating cash flow decreased to $4.7 billion, representing a 50% decrease over 2008.

Capitalized costs incurred in our oil and gas activities were $4.1 billion in 2009.

From an operational perspective, we completed another successful year with the drill-bit. We drilled 1,135 gross wells with an overall 99% rate of success. This success rate enabled us to increase proved reserves by 496 million Boe, which was more than double our 2009 production. Our drilling success was driven by North American Onshore development wells, which represented 95% of the wells drilled.

Besides another successful year of North American Onshore drilling, we had several other key operational achievements during 2009. The first phase of our 100%-owned Jackfish thermal heavy oil project in the Alberta oil sands was operational throughout 2009. As measured by production per well and steam-to-oil ratio, Jackfish is one of Canada s most successful steam-assisted gravity drainage projects. In late 2009, Jackfish s gross production reached 33.7 MBbls of oil per day. The addition of four more producing wells is expected to push production to the facility s capacity of 35 MBbls per day in early 2010.

We continued construction throughout 2009 on a second phase of the Jackfish project. Jackfish 2 is also sized to produce 35 MBbls of oil per day and will commence operations in 2011. Further expansion into a third phase of Jackfish is planned for 2010. We expect to file a regulatory application for Jackfish 3 in the third quarter of 2010.

Elsewhere in North America, we are expanding and developing five natural gas shale plays where we own a total of 1.6 million net acres. At the Barnett Shale, the most mature of our shale plays, we pushed our total producing wells to almost 4,200 at the end of 2009, and we exited the year producing just over one Bcfe per day. In the Cana-Woodford Shale and Arkoma-Woodford Shale, we drilled a total of 108 wells, increasing reserves to 120 MMBoe. In the Haynesville Shale, our drilling has been focused on de-risking our acreage in the greater Carthage area of east Texas. Finally, at Horn River, we have assembled a portfolio of acreage that requires minimal drilling to hold. We are in the early stages of evaluating the full potential of these leases and formulating a development plan.

Even with the net loss, we maintained a solid financial position throughout 2009. We used operating cash flow, borrowings and cash on hand to fund $5.3 billion of capital expenditures and pay $284 million of dividends. At the end of 2009, we had $1.0 billion of cash and $1.8 billion of availability under our credit lines.

Business and Industry Outlook

Over the past decade we captured an abundance of resources. We pioneered horizontal drilling in the Barnett Shale field in north Texas and extended this technique to other natural gas shale plays in the United States and Canada. We became proficient with steam-assisted gravity drainage with our Jackfish oil sands development in Alberta, Canada. We achieved key oil discoveries with our drilling in the deepwater Gulf of Mexico and offshore Brazil. We have more than tripled our proved oil and gas reserves since 2000 and have also assembled an extensive inventory of exploration assets, representing additional unproved resources.

Building off our past successes, in November 2009, we announced plans to strategically reposition Devon as a high-growth, North American onshore exploration and production company. As part of this strategic repositioning, we plan to bring forward the value of our offshore assets located in the Gulf of Mexico and countries outside North America by divesting them.

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This repositioning is driven by our desire to unlock and accelerate the realization of the value underlying the deep inventory of opportunities we have. We have assembled a valuable portfolio of offshore assets, and we have a considerable inventory of premier North American onshore assets. However, our North American Onshore assets have consistently provided us our highest risk-adjusted investment returns. By selling our offshore assets, we can more aggressively pursue the untapped value of these North American Onshore opportunities.

We expect to receive after-tax proceeds of between $4.5 billion and $7.5 billion as we divest our U.S. Offshore and International properties in 2010. By using a portion of these proceeds to reduce debt, we will further strengthen our balance sheet. Besides reducing debt, the offshore divestiture proceeds are expected to provide significant funds to redeploy into our prolific North American Onshore opportunities. With these added funds, we plan to accelerate the growth and realization of the value of our North American Onshore assets.

Results of Operations

As previously stated, we are in the process of divesting our offshore assets. As a result, all amounts in this document related to our International operations are presented as discontinued. Therefore, the production, revenue and expense amounts presented in this Results of Operations section exclude amounts related to our International assets unless otherwise noted. Even though we are also divesting our U.S. Offshore operations, these properties do not qualify as discontinued operations under accounting rules. As such, financial and operating data provided in this document that pertain to our continuing operations include amounts related to our U.S. Offshore operations. To facilitate comparisons of our ongoing operations subsequent to the planned divestitures, we have presented amounts related to our U.S. Offshore assets separate from those of our North American Onshore assets where appropriate.

Unless otherwise stated, all dollar amounts are expressed in U.S. dollars.

Revenues

Our oil, gas and NGL production volumes from 2007 to 2009 are shown in the following table.

	Year Ended December 31,				
	2009	2009 vs. 2008(2)	2008	2008 vs. 2007(2)	2007
Oil (MMBbls)					
U.S. Onshore	12	+3%	11	+0%	11
Canada	25	+17%	22	+34%	16
North American Onshore	37	+12%	33	+20%	27
U.S. Offshore	5	−15%	6	−24%	8
Total	42	+8%	39	+10%	35
Gas (Bcf)					
U.S. Onshore	698	+5%	669	+20%	558
Canada	223	+5%	212	−6%	227
North American Onshore	921	+5%	881	+12%	785
U.S. Offshore	45	−22%	57	−25%	77

Total	966	+3%	938	+9%	862

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	Year Ended December 31,				
	2009	2009 vs. 2008(2)	2008	2008 vs. 2007(2)	2007
NGLs (MMBbls)					
U.S. Onshore	25	+9%	24	+14%	21
Canada	4	−5%	4	−6%	4
North American Onshore	29	+7%	28	+11%	25
U.S. Offshore	1	+27%		−26%	1
Total	30	+7%	28	+10%	26
Total (MMBoe)(1)					
U.S. Onshore	154	+5%	146	+17%	124
Canada	66	+9%	61	+5%	58
North American Onshore	220	+6%	207	+13%	182
U.S. Offshore	13	−18%	16	−25%	22
Total	233	+4%	223	+9%	204

(1) 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 gas and oil, which rate is not necessarily indicative of the relationship of gas and oil 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 the table.

The following table presents the prices we realized on our production volumes from 2007 to 2009. These prices exclude any effects due to our oil and gas derivative financial instruments.

	Year Ended December 31,				
	2009	2009 vs. 2008(2)	2008	2008 vs. 2007(2)	2007
Oil (per Bbl)					
U.S. Onshore	$ 56.17	−41%	$ 95.63	+42%	$ 67.34
Canada	$ 47.35	−33%	$ 71.04	+43%	$ 49.80
North American Onshore	$ 50.11	−37%	$ 79.45	+39%	$ 56.99
U.S. Offshore	$ 60.75	−42%	$ 104.90	+46%	$ 71.95
Total	$ 51.39	−38%	$ 83.35	+38%	$ 60.30
Gas (per Mcf)					
U.S. Onshore	$ 3.14	−58%	$ 7.43	+30%	$ 5.69
Canada	$ 3.66	−55%	$ 8.17	+31%	$ 6.24

North American Onshore	$	3.27	−57%	$	7.61	+30%	$	5.85
U.S. Offshore	$	4.20	−56%	$	9.53	+33%	$	7.17
Total	$	3.31	−57%	$	7.73	+29%	$	5.97

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	Year Ended December 31,				
	2009	2009 vs. 2008(2)	2008	2008 vs. 2007(2)	2007
NGLs (per Bbl)					
U.S. Onshore	$ 23.40	−43%	$ 40.97	+14%	$ 36.08
Canada	$ 33.09	−46%	$ 61.45	+33%	$ 46.07
North American Onshore	$ 24.65	−44%	$ 43.94	+16%	$ 37.80
U.S. Offshore	$ 27.42	−46%	$ 51.11	+39%	$ 36.78
Total	$ 24.71	−44%	$ 44.08	+17%	$ 37.76
Combined (per Boe)(1)					
U.S. Onshore	$ 22.41	−53%	$ 47.91	+28%	$ 37.45
Canada	$ 32.29	−44%	$ 57.65	+39%	$ 41.51
North American Onshore	$ 25.38	−50%	$ 50.78	+31%	$ 38.74
U.S. Offshore	$ 38.83	−48%	$ 74.55	+40%	$ 53.30
Total	$ 26.15	−50%	$ 52.49	+30%	$ 40.26

(1) 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 gas and oil, which rate is not necessarily indicative of the relationship of gas and oil 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 the table.

The volume and price changes in the tables above caused the following changes to our oil, gas and NGL sales between 2007 and 2009.

	Oil	Gas	NGL	Total
		(In millions)		
2007 sales	$ 2,117	$ 5,138	$ 970	$ 8,225
Changes due to volumes	222	459	95	776
Changes due to prices	894	1,647	178	2,719
2008 sales	3,233	7,244	1,243	11,720
Changes due to volumes	258	222	89	569
Changes due to prices	(1,338)	(4,269)	(585)	(6,192)
2009 sales	$ 2,153	$ 3,197	$ 747	$ 6,097

Oil Sales

2009 vs. 2008 Oil sales decreased $1.3 billion as a result of a 38% decrease in our realized price without hedges. The average NYMEX West Texas Intermediate index price decreased 38% during the same time period, accounting for the majority of the decrease in our realized price.

Oil sales increased $258 million due to a three million barrel, or 8%, increase in production. The increased production resulted primarily from the continued development of our Jackfish thermal heavy oil project in Canada.

2008 vs. 2007 Oil sales increased $894 million as a result of a 38% increase in our realized price without hedges. The average NYMEX West Texas Intermediate index price increased 38% during the same time period, accounting for the majority of the increase in our realized price.

Oil sales increased $222 million due to a four million barrel, or 10%, increase in production. Production from our Canadian operations increased approximately six million barrels in 2008 as a result of first oil sales at Jackfish and heavy oil development activity at Lloydminster. This increase was partially offset by the deferral of 0.5 million barrels of oil production from our U.S. Offshore properties due to hurricanes.

Gas Sales

2009 vs. 2008 Gas sales decreased $4.3 billion as a result of a 57% decrease in our realized price without hedges. This decrease was largely due to decreases in the North American regional index prices upon which our gas sales are based.

A 28 Bcf, or 3%, increase in production during 2009 caused gas sales to increase by $222 million. Our North American Onshore properties contributed 40 Bcf of higher volumes. This increase included 25 Bcf of higher production in Canada due to a decline in Canadian government royalties, resulting largely from lower gas prices. The remainder of the North American Onshore growth resulted from new drilling and development that exceeded natural production declines, primarily in the Barnett Shale field in north Texas. These increases were partially offset by 12 Bcf of lower production from our U.S. Offshore properties, largely resulting from natural production declines.

2008 vs. 2007 Gas sales increased $1.6 billion as a result of a 29% increase in our realized price without hedges. This increase was largely due to increases in the North American regional index prices upon which our gas sales are based.

A 76 Bcf, or 9%, increase in production during 2008 caused gas sales to increase by $459 million. Our North American Onshore properties contributed 96 Bcf to our growth as a result of new drilling and development that exceeded natural production declines. This increase was led by our drilling and development program in the Barnett Shale, which contributed 83 Bcf to the gas production increase. This increase and the effect of new drilling and development in our other North American Onshore properties were partially offset by natural production declines and the deferral of seven Bcf of production in our U.S. Offshore properties in 2008 due to hurricanes.

NGL Sales

2009 vs. 2008 NGL sales decreased $585 million as a result of a 44% decrease in our realized price without hedges. This decrease was largely due to decreases in the regional index prices upon which our U.S. Onshore NGL sales are based. NGL sales increased $89 million in 2009 due to a two million barrel, or 7%, increase in production. The increase in production is primarily due to drilling and development in the Barnett Shale.

2008 vs. 2007 NGL sales increased $178 million as a result of a 17% increase in our realized price without hedges. This increase was largely due to increases in the regional index prices upon which our U.S. Onshore NGL sales are based. NGL sales increased $95 million in 2008 due to a two million barrel, or 10%, increase in production. The increase in production is primarily due to Barnett Shale drilling and development.

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Net Gain (Loss) on Oil and Gas Derivative Financial Instruments

The following tables provide financial information associated with our oil and gas derivative financial instruments from 2007 to 2009. The first table presents the cash settlements and unrealized gains and losses recognized as components of our revenues. The subsequent tables present our oil, gas and NGL prices with, and without, the effects of the cash settlements from 2007 to 2009. The prices do not include the effects of unrealized gains and losses.

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Cash settlement receipts (payments):			
Gas price collars	$ 450	$ (221)	$ 2
Gas price swaps	55	(203)	38
Oil price collars		27	
Total cash settlements	505	(397)	40
Unrealized (losses) gains on fair value changes:			
Gas price collars	(255)	255	(4)
Gas price swaps	169	(12)	(22)
Gas basis swaps	3		
Oil price collars	(38)		
Total unrealized (losses) gains on fair value changes	(121)	243	(26)
Net gain (loss)	$ 384	$ (154)	$ 14

	Year Ended December 31, 2009			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 51.39	$ 3.31	$ 24.71	$ 26.15
Cash settlements of hedges		0.52		2.16
Realized price, including cash settlements	$ 51.39	$ 3.83	$ 24.71	$ 28.31

	Year Ended December 31, 2008			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 83.35	$ 7.73	$ 44.08	$ 52.49

Cash settlements of hedges	0.70	(0.46)		(1.78)
Realized price, including cash settlements	$ 84.05	$ 7.27	$ 44.08	$ 50.71

	Year Ended December 31, 2007			
	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Total (Per Boe)
Realized price without hedges	$ 60.30	$ 5.97	$ 37.76	$ 40.26
Cash settlements of hedges		0.04		0.20
Realized price, including cash settlements	$ 60.30	$ 6.01	$ 37.76	$ 40.46

Our oil and gas derivative financial instruments include price swaps, basis swaps and costless price collars. For the price swaps, we receive a fixed price for our production and pay a variable market price to the contract counterparty. For the basis swaps, we receive a fixed differential between two regional gas index prices and pay a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we cash-settle the difference with the counterparty to the collars. Cash settlements as presented in the tables above represent realized gains or losses related to our price swaps and collars.

In addition to recognizing these cash settlement effects, we also recognize unrealized changes in the fair values of our oil and gas derivative instruments in each reporting period. We estimate the fair values of our oil and gas derivative financial instruments primarily by using internal discounted cash flow calculations. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers.

The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Based on the amount of volumes subject to our gas price swaps and collars at December 31, 2009, a 10% increase in these forward curves would have increased our 2009 unrealized losses for our gas derivative financial instruments by approximately $264 million. A 10% increase in the forward curves associated with our oil derivative financial instruments would have increased our 2009 unrealized losses by approximately $108 million. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility.

Counterparty credit risk is also a component of commodity derivative valuations. We have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with twelve separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of December 31, 2009, the credit ratings of all our counterparties were investment grade.

During 2009, the fair value of our oil and gas derivative financial instruments dropped by $121 million. This reduction largely resulted from the reversal of previously recorded unrealized gains on our gas price collar contracts, which was expected as the contracts settled throughout 2009 and expired on December 31, 2009. This reduction, as well as the reduction related to our oil price collars, were partially offset by unrealized gains on gas swap contracts that we entered into during 2009 and will be settled throughout 2010.

During 2008, the fair value of our gas derivative financial instruments increased by $243 million, which was largely due to a decrease in the Inside FERC Henry Hub forward curve.

Marketing and Midstream Revenues and Operating Costs and Expenses

The changes in marketing and midstream revenues, operating costs and expenses and the resulting operating profit between 2007 and 2009 are shown in the table below.

	Year Ended December 31,				
	2009	2009 vs 2008(1)	2008	2008 vs 2007(1)	2007
	($ in millions)				
Marketing and midstream:					
Revenues	$ 1,534	−33%	$ 2,292	+32%	$ 1,736

Operating costs and expenses	1,022	−37%	1,611	+32%	1,217
Operating profit	$ 512	−25%	$ 681	+31%	$ 519

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

2009 vs. 2008 Marketing and midstream revenues decreased $758 million and operating costs and expenses decreased $589 million, causing operating profit to decrease $169 million. Both revenues and expenses decreased primarily due to lower natural gas and NGL prices, partially offset by higher NGL production and gas pipeline throughput.

2008 vs. 2007 Marketing and midstream revenues increased $556 million and operating costs and expenses increased $394 million, causing operating profit to increase $162 million. Both revenues and expenses increased primarily due to higher natural gas and NGL prices and increased gas pipeline throughput.

Lease Operating Expenses (LOE)

The changes in LOE between 2007 and 2009 are shown in the table below.

	Year Ended December 31,				
	2009	2009 vs. 2008(1)	2008	2008 vs. 2007(1)	2007
Lease operating expenses ($ in millions):					
U.S. Onshore	$ 838	−6%	$ 893	+25%	$ 712
Canada	673	−13%	776	+24%	627
North American Onshore	1,511	−10%	1,669	+25%	1,339
U.S. Offshore	159	−13%	182	−6%	193
Total	$ 1,670	−10%	$ 1,851	+21%	$ 1,532
Lease operating expenses per Boe:					
U.S. Onshore	$ 5.46	−11%	$ 6.11	+7%	$ 5.70
Canada	$ 10.15	−20%	$ 12.74	+18%	$ 10.80
North American Onshore	$ 6.87	−15%	$ 8.06	+10%	$ 7.32
U.S. Offshore	$ 11.98	+6%	$ 11.29	+25%	$ 9.04
Total	$ 7.16	−14%	$ 8.29	+11%	$ 7.50

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

2009 vs. 2008 LOE decreased $181 million in 2009. LOE dropped $182 million due to declining costs for fuel, materials, equipment and personnel, as well as declines in maintenance and well workover projects. Such declines largely resulted from decreasing demand for field services due to lower oil and gas prices. Changes in the exchange rate between the U.S. and Canadian dollar reduced LOE $49 million. Additionally, LOE decreased $31 million as a result of hurricane damages in 2008 to certain of our U.S. Offshore facilities and transportation systems. These factors were also the main contributors to the decrease in LOE per Boe on our North American Onshore properties. Production growth at our large-scale Jackfish project also contributed to a decrease in LOE per Boe. As Jackfish production approached the facility s capacity during 2009, its per-unit costs declined, contributing to lower overall LOE per Boe. The remainder of our 4% production growth added $81 million to LOE during 2009.

2008 vs. 2007 LOE increased $319 million in 2008. The largest individual contributor to this increase, as well as the increase in LOE per Boe, was higher per-unit costs associated with the new thermal heavy oil production at Jackfish in 2008. When large-scale projects such as Jackfish are in the early phases of production, per-unit operating costs are normally higher than the per-unit costs for our overall portfolio of producing properties. LOE also increased $144 million due to our 9% growth in production. Additionally, LOE increased $31 million due to hurricane damages in 2008 to certain of our U.S. Offshore facilities and transportation systems. These hurricane damages also contributed to the increase in LOE per Boe.

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Taxes Other Than Income Taxes

Taxes other than income taxes primarily consist of production taxes and ad valorem taxes assessed by various government agencies on our U.S. Onshore properties. Production taxes are based on a percentage of production revenues that varies by property and government jurisdiction. Ad valorem taxes generally are based on property values as determined by the government agency assessing the tax. The following table details the changes in our taxes other than income taxes between 2007 and 2009.

	Year Ended December 31,				
	2009	2009 vs 2008(1)	2008	2008 vs 2007(1)	2007
	($ in millions)				
Production	$ 132	−57%	$ 306	+41%	$ 216
Ad valorem	175	+8%	162	+19%	135
Other	7	−4%	8	+20%	7
Total	$ 314	−34%	$ 476	+33%	$ 358

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

2009 vs. 2008 Production taxes decreased $174 million in 2009. This decrease was largely due to lower U.S. Onshore revenues, as well as an increase in tax credits associated with certain properties in the state of Texas. Ad valorem taxes increased $13 million primarily due to higher assessed oil and gas property and equipment values.

2008 vs. 2007 Production taxes increased $90 million in 2008 primarily due to an increase in our U.S. Onshore revenues. Ad valorem taxes increased $27 million primarily due to higher assessed oil and gas property and equipment values.

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 our capitalized investment, net of accumulated DD&A and reductions of carrying value, plus future development costs related to proved undeveloped reserves. Generally, when reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, when the depletable base changes, then the DD&A rate moves in the same direction. The per unit DD&A rate is not affected by production volumes. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes. Oil and gas property DD&A is calculated separately on a country-by-country basis.

The changes in our production volumes, DD&A rate per unit and DD&A of oil and gas properties between 2007 and 2009 are shown in the table below.

Year Ended December 31,

	2009	2009 vs 2008(1)	2008	2008 vs 2007(1)	2007
Total production volumes (MMBoe)	233	+4%	223	+9%	204
DD&A rate ($ per Boe)	$ 7.86	−40%	$ 13.20	+12%	$ 11.81
DD&A expense ($ in millions)	$ 1,832	−38%	$ 2,948	+22%	$ 2,412

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

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The following table details the changes in DD&A of oil and gas properties between 2007 and 2009 due to the changes in production volumes and DD&A rate presented in the table above.

	(In millions)
2007 DD&A	$ 2,412
Change due to volumes	224
Change due to rate	312
2008 DD&A	2,948
Change due to volumes	130
Change due to rate	(1,246)
2009 DD&A	$ 1,832

2009 vs. 2008 Oil and gas property related DD&A decreased $1.2 billion due to a 40% decrease in the DD&A rate. The largest contributors to the rate decrease were reductions of the carrying values of certain of our oil and gas properties recognized in the first quarter of 2009 and the fourth quarter of 2008. These reductions totaled $16.3 billion and resulted from full cost ceiling limitations in the United States and Canada. In addition, the effects of changes in the exchange rate between the U.S. and Canadian dollar also contributed to the rate decrease. These factors were partially offset by the effects of costs incurred and the transfer of previously unproved costs to the depletable base as a result of 2009 drilling activities. Partially offsetting the impact from the lower 2009 DD&A rate was our 4% production increase, which caused oil and gas property related DD&A expense to increase $130 million.

Our 2009 DD&A rate reflects our adoption of the SEC s *Modernization of Oil and Gas Reporting*. The impact of adopting the SEC s new rules at the end of 2009 had virtually no impact on our 2009 DD&A rate.

2008 vs. 2007 Oil and gas property related DD&A increased $312 million due to a 12% increase in the DD&A rate. The largest contributor to the rate increase was inflationary pressure on both the costs incurred during 2008 as well as the estimated development costs to be spent in future periods on proved undeveloped reserves. Other factors that contributed to the rate increase were reductions in reserve estimates due to lower 2008 year-end commodity prices and the transfer of previously unproved costs to the depletable base as a result of 2008 drilling activities. In addition to the impact from the higher 2008 rate, the 9% production increase caused oil and gas property related DD&A expense to increase $224 million.

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 offset by two 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

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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,				
	2009	2009 vs 2008(1)	2008	2008 vs 2007(1)	2007
			($ in millions)		
Gross G&A	$ 1,107	+0%	$ 1,103	+24%	$ 903
Capitalized G&A	(332)	−2%	(337)	+26%	(277)
Reimbursed G&A	(127)	+5%	(121)	+7%	(113)
Net G&A	$ 648	+0%	$ 645	+26%	$ 513

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

2009 vs. 2008 Gross G&A increased $4 million. This increase was due to approximately $60 million of higher costs for employee compensation and benefits, mostly offset by the effects of our 2009 reduced spending initiatives for certain discretionary cost categories.

Employee cost increases in 2009 included an additional $57 million of severance costs. This increase was primarily due to Gulf of Mexico employees that were impacted by the integration of our Gulf of Mexico and International operations into one offshore unit in the second quarter of 2009 and other employee departures during 2009. Additionally, postretirement benefits costs increased approximately $50 million. The increases in employee costs were partially offset by a $27 million decrease due to accelerated share-based compensation expense recognized in 2008 as discussed below.

2008 vs. 2007 Gross G&A increased $200 million. The largest contributors to the increase were higher employee compensation and benefits costs. These cost increases, which were largely related to our growth and industry inflation during most of 2008, caused gross G&A to increase $164 million. Of this increase, $65 million related to higher stock compensation.

Stock compensation increased $43 million in 2008 due to a modification of the share-based compensation arrangements for certain executives. The modified compensation arrangements provide that executives who meet certain years-of-service and age criteria can retire and continue vesting in outstanding share-based grants. As a condition to receiving the benefits of these modifications, the executives must agree not to use or disclose Devon s confidential information and not to solicit Devon s employees and customers. The executives are required to agree to these conditions at retirement and again in each subsequent year until all grants have vested.

Although this modification does not accelerate the vesting of the executives grants, it does accelerate the expense recognition as executives approach the years-of-service and age criteria. When the modification was made in 2008, certain executives had already met the years-of-service and age criteria. As a result, we recognized $27 million of share-based compensation expense in the second quarter of 2008 related to this modification. In the fourth quarter of 2008, we recognized an additional $16 million of stock compensation for grants made to these executives. The additional expenses would have been recognized in future reporting periods if the modification had not been made and the executives continued their employment at Devon.

The higher employee compensation and benefits costs, exclusive of the accelerated stock compensation expense, were also the primary factors that caused the $60 million increase in capitalized G&A in 2008.

Restructuring Costs

In the fourth quarter of 2009, we recognized $153 million of estimated employee severance costs associated with the planned divestitures of our offshore assets that was announced in November 2009. This amount was based on our estimates of the number of employees that will ultimately be impacted by the divestitures, and includes $63 million related to accelerated vesting of share-based grants. Of the $153 million total, $105 million relates to our U.S. Offshore operations and the remainder relates to our International discontinued operations.

As of the date of this report, only one of the properties we intend to sell had actually been sold. Furthermore, the vast majority of employees will not be impacted by the divestitures until the properties are sold. Therefore, our estimate of employee severance costs recognized in the fourth quarter of 2009 was based upon certain key estimates that could change as properties are sold. These estimates include the number of impacted employees, the number of employees offered comparable positions with the buyers and the date of separation for impacted employees. If our estimate of the number of impacted employees were to increase 10%, our estimate of employee severance costs would increase approximately $10 million. If our estimate of the number of employees offered comparable positions with the buyers were to decrease by 10%, our estimate of employee severance costs would increase approximately $15 million. Additionally, if the date of separation were to occur one month after our current estimates, our estimate of employee severance costs would increase approximately $2 million.

Interest Expense

The following table includes the components of interest expense between 2007 and 2009.

	Year Ended December 31,		
	2009	2008	2007
		(In millions)	
Interest based on debt outstanding	$ 437	$ 426	$ 508
Capitalized interest	(94)	(111)	(102)
Other	6	14	24
Total interest expense	$ 349	$ 329	$ 430

2009 vs. 2008 Interest based on debt outstanding increased $11 million from 2008 to 2009. This increase was primarily due to interest paid on the $500 million of 5.625% senior unsecured notes and $700 million of 6.30% senior unsecured notes that we issued in January 2009. This was partially offset by lower interest resulting from the retirement of our exchangeable debentures during the third quarter of 2008 and lower interest rates on our floating-rate commercial paper borrowings.

Capitalized interest decreased from 2008 to 2009 primarily due to the sales of our West African exploration and development properties in 2008 and the completion of the Access pipeline transportation system in Canada in the second quarter of 2008.

2008 vs. 2007 Interest based on debt outstanding decreased $82 million from 2007 to 2008. This decrease was largely due to lower average outstanding amounts for commercial paper and credit facility borrowings in 2008 than in 2007. The decrease in borrowings resulted largely from the use of proceeds from our West African divestiture program and cash flow from operations to repay all commercial paper and credit facility borrowings in the second quarter of 2008. Additionally, we retired debentures with a face value of $652 million during 2008, primarily during the third quarter.

Capitalized interest increased from 2007 to 2008 primarily due to higher cumulative costs related to large-scale development projects in the Gulf of Mexico, partially offset by lower capitalized interest resulting from the completion of the Access pipeline in the second quarter of 2008.

Change in Fair Value of Other Financial Instruments

The details of the changes in fair value of other financial instruments between 2007 and 2009 are shown in the table below.

	Year Ended December 31, 2009	2008	2007
	(In millions)		
(Gains) losses from:			
Interest rate swaps fair value changes	$ (66)	$ (104)	$ (1)
Interest rate swaps settlements	(40)	(1)	
Chevron common stock		363	(281)
Option embedded in exchangeable debentures		(109)	248
Total	$ (106)	$ 149	$ (34)

Interest Rate Swaps

We recognize unrealized changes in the fair values of our interest rate swaps each reporting period. We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties or brokers. In 2009 and 2008, we recorded unrealized gains of $66 million and $104 million, respectively, as a result of changes in interest rates. Also, during 2009 and 2008, we received cash settlements totaling $40 million and $1 million, respectively, from counterparties to settle our interest rate swaps. There were no cash settlements in 2007.

The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by a third party. Based on the notional amount subject to the interest rate swaps at December 31, 2009, a 10% increase in these forward curves would have increased our 2009 unrealized gain for our interest rate swaps by approximately $46 million.

Similar to our commodity derivative contracts, counterparty credit risk is also a component of interest rate derivative valuations. We have mitigated our exposure to any single counterparty by contracting with several counterparties. Our interest rate derivative contracts are held with seven separate counterparties. Additionally, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. The credit ratings of all our counterparties were investment grade as of December 31, 2009.

Chevron Common Stock and Related Embedded Option

Until October 31, 2008, we owned 14.2 million shares of Chevron common stock and recognized unrealized changes in the fair value of this investment. On October 31, 2008, we exchanged these shares of Chevron common stock for Chevron s interest in the Drunkard s Wash properties located in east-central Utah and $280 million in cash. In accordance with the terms of the exchange, the fair value of our investment in the Chevron shares was estimated to be

$67.71 per share on the exchange date. Prior to the exchange of these shares, we calculated the fair value of our investment in Chevron common stock using Chevron s published market price.

We also recognized unrealized changes in the fair value of the conversion option embedded in the debentures exchangeable into shares of Chevron common stock. The embedded option was not actively traded in an established market. Therefore, we estimated its fair value using quotes obtained from a broker for trades occurring near the valuation date.

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The loss during 2008 on our investment in Chevron common stock was directly attributable to a $25.62 per share decrease in the estimated fair value while we owned Chevron s common stock during the year. The gain on the embedded option during 2008 was directly attributable to the change in fair value of the Chevron common stock from January 1, 2008 to the maturity date of August 15, 2008. The gain on our investment in Chevron common stock and loss on the embedded option during 2007 were directly attributable to a $19.80 increase in the price per share of Chevron s common stock during 2007.

Reduction of Carrying Value of Oil and Gas Properties

During 2009 and 2008, we reduced the carrying values of certain of our oil and gas properties due to full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

	Year Ended December 31,			
	2009		2008	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
United States	$ 6,408	$ 4,085	$ 6,538	$ 4,168
Canada			3,353	2,488
Total	$ 6,408	$ 4,085	$ 9,891	$ 6,656

The 2009 reduction was recognized in the first quarter and the 2008 reductions were recognized in the fourth quarter. The reductions resulted from significant decreases in each country s full cost ceiling compared to the immediately preceding quarter. The lower United States ceiling value in the first quarter of 2009 largely resulted from the effects of declining natural gas prices subsequent to December 31, 2008. The lower ceiling values in the fourth quarter of 2008 largely resulted from the effects of sharp declines in oil, gas and NGL prices compared to September 30, 2008.

To demonstrate these declines, the March 31, 2009, December 31, 2008 and September 30, 2008 weighted average wellhead prices are presented in the following table.

	March 31, 2009			December 31, 2008			September 30, 2008		
Country	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)	Oil (Per Bbl)	Gas (Per Mcf)	NGLs (Per Bbl)
United States	$ 47.30	$ 2.67	$ 17.04	$ 42.21	$ 4.68	$ 16.16	$ 97.62	$ 5.28	$ 38.00
Canada	N/A	N/A	N/A	$ 23.23	$ 5.31	$ 20.89	$ 59.72	$ 6.00	$ 62.78

N/A Not applicable.

The March 31, 2009 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $49.66 per Bbl for crude oil and the Henry Hub spot price of $3.63 per MMBtu for gas. The December 31, 2008 oil and gas wellhead prices in the table above compare to the NYMEX cash price of $44.60 per Bbl for crude oil and the Henry

Hub spot price of $5.71 per MMBtu for gas. The September 30, 2008, wellhead prices in the table compare to the NYMEX cash price of $100.64 per Bbl for crude oil and the Henry Hub spot price of $7.12 per MMBtu for gas.

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Other Income

The following table includes the components of other income between 2007 and 2009.

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Interest and dividend income	$ 8	$ 54	$ 48
Reduction of deep water royalties	84		
Hurricane insurance proceeds		162	
Other	(24)	1	3
Total	$ 68	$ 217	$ 51

Interest and dividend income decreased from 2008 to 2009 due to a decrease in dividends received on our previously owned investment in Chevron common stock and a decrease in interest received on cash equivalents due to lower rates and balances. Interest and dividend income increased from 2007 to 2008 primarily due to higher cash balances partially offset by lower interest rates and a decrease in dividends received on our investment in Chevron common stock.

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 gas exceeded the thresholds for a given year, royalty relief would not be granted for that year.

In October 2007, a federal district court ruled in favor of a plaintiff who had challenged the legality of including price thresholds in deep water leases. Additionally, in January 2009 a federal appellate court upheld this district court ruling. This judgment was later appealed to the United States Supreme Court, which, in October 2009, declined to review the appellate court s ruling. The Supreme Court s decision ended the MMS s judicial course to enforce the price thresholds.

Prior to September 30, 2009, we had $84 million accrued for potential royalties on various deep water leases. Based upon the Supreme Court s decision, we reduced to zero the $84 million loss contingency accrual in the third quarter of 2009.

In 2008, we recognized $162 million of excess insurance recoveries for damages suffered in 2005 related to hurricanes that struck the Gulf of Mexico. The excess recoveries resulted from business interruption claims on policies that were in effect when the 2005 hurricanes occurred.

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Income Taxes

The following table presents our total income tax (benefit) 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 2007 to 2009, and differ from the U.S. statutory rate, are discussed below.

	Year Ended December 31,		
	2009	**2008**	**2007**
Total income tax (benefit) expense (In millions)	$ (1,773)	$ (1,121)	$ 842
U.S. statutory income tax rate	(35)%	(35)%	35%
State income taxes	(2)%	(1)%	1%
Taxation on Canadian operations	(1)%	5%	
Repatriations and tax policy election changes		7%	
Canadian statutory rate reduction			(8)%
Other	(1)%	(3)%	(3)%
Effective income tax (benefit) expense rate	(39)%	(27)%	25%

For 2008, our effective income tax rate differed from the U.S. statutory income tax rate largely due to two related factors. First, during 2008, we repatriated $2.6 billion from certain foreign subsidiaries to the United States. Second, we made certain tax policy election changes in the second quarter of 2008 to minimize the taxes we otherwise would pay for the cash repatriations, as well as the taxable gains associated with the sales of assets in West Africa. As a result of the repatriation and tax policy election changes, we recognized additional tax expense of $312 million during 2008. Of the $312 million, $295 million was recognized as current income tax expense, and $17 million was recognized as deferred tax expense. Excluding the $312 million of additional tax expense, our effective income tax benefit rate would have been 34% for 2008.

In 2007, deferred income taxes were reduced $261 million due to a Canadian statutory rate reduction that was enacted in that year.

Earnings From Discontinued Operations

For all years presented in the following tables, our discontinued operations include amounts related to our assets in Azerbaijan, Brazil, China and other minor International properties that we are in the process of divesting. Additionally, during 2007 and 2008, our discontinued operations included amounts related to our assets in Egypt and West Africa, including Equatorial Guinea, Cote d Ivoire, Gabon and other countries in the region until they were sold. Following are the components of earnings from discontinued operations between 2007 and 2009.

	Year Ended December 31, 2009	2008	2007
Total production (MMBoe)	16	18	32
Combined price without hedges (per Boe)	$ 59.25	$ 92.72	$ 68.11
		(In millions)	
Operating revenues	$ 945	$ 1,702	$ 2,168
Expenses and other income, net:			
Operating expenses	484	769	597
Restructuring costs	48		
Reduction of carrying value of oil and gas properties	108	494	68
Gain on sale of oil and gas properties	(17)	(819)	(90)
Total expenses and other income, net	623	444	575
Earnings before income taxes	322	1,258	1,593
Income tax expense	48	367	472
Earnings from discontinued operations	$ 274	$ 891	$ 1,121

Our African sales generated total proceeds of $3.0 billion. The following table presents the gains on the African divestiture transactions by year.

	Year Ended December 31, 2009		2008		2007	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
			(In millions)			
Egypt	$	$	$	$	$ 90	$ 90
Equatorial Guinea			619	544		
Gabon			117	122		
Cote d Ivoire	17	17	83	95		
Other				8		
Total	$ 17	$ 17	$ 819	$ 769	$ 90	$ 90

2009 vs. 2008 Earnings from discontinued operations decreased $617 million in 2009. Our discontinued earnings were impacted by several factors. First, operating revenues declined largely due to a 36% decrease in the price realized on our production, which was driven by a decline in crude oil index prices. Second, both operating revenues and expenses declined due to divestitures that closed in 2008. Discontinued earnings also decreased due to $48 million of restructuring costs that relate to our planned divestitures and were recognized in the fourth quarter of 2009. These costs consist of employee severance costs. Earnings also decreased $752 million in 2009 due to larger gains recognized on West African asset divestitures in 2008.

Partially offsetting these decreased earnings in 2009 was the larger reduction of carrying value recognized in 2008 compared to 2009. The reductions largely consisted of full cost ceiling limitations related to our assets in Brazil that were caused by a decline in oil prices.

2008 vs. 2007 Earnings from discontinued operations decreased $230 million in 2008. Our earnings were impacted by several factors. First, operating revenues and expenses, including the related production volumes, decreased largely due to the timing of our 2008 and 2007 divestitures, partially offset by the effects of first production in Brazil. Discontinued earnings also decreased due to the net effect of reductions in carrying value recognized in 2008 and 2007, which largely related to our assets in Brazil. Discontinued earnings increased $679 million in 2008 due to the larger African divestiture gains in 2008.

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Capital Resources, Uses and Liquidity

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

Sources and Uses of Cash

The following table presents the sources and uses of our cash and cash equivalents from 2007 to 2009. The table presents capital expenditures on a cash basis. Therefore, these amounts differ from capital expenditure amounts that include accruals and are referred to elsewhere in this document. Additional discussion of these items follows the table.

	2009	2008	2007
		(In millions)	
Sources of cash and cash equivalents:			
Operating cash flow continuing operations	$ 4,232	$ 8,448	$ 5,308
Sales of property and equipment	34	117	76
Net credit facility borrowings			1,450
Net commercial paper borrowings	1,431	1	
Proceeds from debt issuance, net of commercial paper repayments	182		
Net decrease in investments	7	250	202
Stock option exercises	42	116	91
Proceeds from exchange of Chevron stock		280	
Cash distributed from discontinued operations		1,898	
Other	8	59	43
Total sources of cash and cash equivalents	5,936	11,169	7,170
Uses of cash and cash equivalents:			
Capital expenditures	(4,879)	(8,843)	(5,709)
Net credit facility repayments		(1,450)	
Net commercial paper repayments			(804)
Debt repayments	(178)	(1,031)	(567)
Repurchases of common stock		(665)	(326)
Redemption of preferred stock		(150)	
Dividends	(284)	(289)	(259)
Other	(17)		
Total uses of cash and cash equivalents	(5,358)	(12,428)	(7,665)
Increase (decrease) from continuing operations	578	(1,259)	(495)
Increase from discontinued operations, net of distributions to continuing operations	6	386	1,061
Effect of foreign exchange rates	43	(116)	51
Net increase (decrease) in cash and cash equivalents	$ 627	$ (989)	$ 617
Cash and cash equivalents at end of year	$ 1,011	$ 384	$ 1,373

Short-term investments at end of year	$	$	$ 372

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Operating Cash Flow Continuing Operations

Net cash provided by operating activities (operating cash flow) continued to be our primary source of capital and liquidity in 2009. Changes in operating cash flow from our continuing operations 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, financial instrument fair value changes, property impairments and deferred income taxes. As a result, our operating cash flow decreased 50% during 2009 primarily due to the significant decrease in oil, gas and NGL sales, net of commodity hedge settlements, as discussed in the Results of Operations section of this report.

During 2009, our operating cash flow funded approximately 87% of our cash payments for capital expenditures. Commercial paper borrowings were used to fund the remainder of our cash-based capital expenditures. During 2008 and 2007 our capital expenditures were primarily funded by our operating cash flow and pre-existing cash balances.

Other Sources of Cash Continuing and Discontinued Operations

As needed, we supplement our operating cash flow with cash on hand and access to our available credit under our credit facilities and commercial paper program. We may also issue long-term debt to supplement our operating cash flow while maintaining adequate liquidity under our credit facilities. Additionally, we sometimes acquire short-term investments to maximize our income on available cash balances. As needed, we may reduce our investment balances to further supplement our operating cash flow.

In January 2009, we issued $500 million of 5.625% senior unsecured notes due January 15, 2014 and $700 million of 6.30% senior unsecured notes due January 15, 2019. The net proceeds received of $1.187 billion, after discounts and issuance costs, were used primarily to repay Devon s $1.005 billion of outstanding commercial paper as of December 31, 2008.

Subsequent to the $1.0 billion commercial paper repayment in January 2009, we utilized additional commercial paper borrowings of $1.4 billion to fund capital expenditure and dividend payments in excess of our operating cash flow during 2009.

During 2008, we reduced our short-term investment balances by $250 million. We also received $280 million from the exchange of our investment in Chevron common stock, $117 million from the sale of non-oil and gas property and equipment and $116 million from stock option exercises. Another significant source of cash was our African divestiture program. In 2008, we received $2.6 billion in proceeds ($1.9 billion net of income taxes and purchase price adjustments) from sales of assets located in Equatorial Guinea and other West African countries. Also, in conjunction with these asset sales, we repatriated an additional $2.6 billion of earnings from certain foreign subsidiaries to the United States. We used these combined sources of cash in 2008 to fund debt repayments, common stock repurchases, redemptions of preferred stock and dividends on common and preferred stock.

During 2007, we borrowed $1.5 billion under our unsecured revolving line of credit and reduced our short-term investment balances by $202 million. We also received $341 million of proceeds from the sale of our Egyptian operations. These sources of cash were used primarily to fund net commercial paper repayments, long-term debt repayments, common stock repurchases and dividends on common and preferred stock.

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Capital Expenditures

Following are the components of our capital expenditures for the years ended 2009, 2008 and 2007. The amounts in the table below reflect cash payments for capital expenditures, including cash paid for capital expenditures incurred. Capital expenditures actually incurred during 2009, 2008 and 2007 were approximately $4.7 billion, $10.0 billion and $5.9 billion, respectively.

	2009	2008 (In millions)	2007
U.S. Onshore	$ 2,413	$ 5,606	$ 3,280
Canada	1,064	1,459	1,232
North American Onshore	3,477	7,065	4,512
U.S. Offshore	845	1,157	687
Total exploration and development	4,322	8,222	5,199
Midstream	323	451	370
Other	234	170	141
Total continuing operations	$ 4,879	$ 8,843	$ 5,710

Our capital expenditures consist of amounts related to our oil and gas exploration and development operations, our midstream operations and other corporate activities. The vast majority of our capital expenditures are for the acquisition, drilling or development of oil and gas properties, which totaled $4.3 billion, $8.2 billion and $5.2 billion in 2009, 2008 and 2007, respectively. The decrease in capital expenditures from 2008 to 2009 was due to decreased drilling activities in most of our operating areas in response to lower commodity prices in 2009 compared to recent years. The 2008 capital expenditures include $2.6 billion related to acquisitions of properties in Texas, Louisiana, Oklahoma and Canada. Excluding the effect of the 2008 acquisitions, the increase in capital expenditures from 2007 to 2008 was due to increased drilling activities in the Barnett Shale, Gulf of Mexico, Carthage, Groesbeck and Washakie areas of the United States and the Lloydminster and Jackfish projects in Canada. Expenditures in the first half of 2008 also increased due to inflationary pressure driven by increased competition for field services.

Our capital expenditures for our midstream operations are primarily for the construction and expansion of natural gas processing plants, natural gas pipeline systems and oil pipelines. These midstream facilities exist primarily to support our oil and gas development operations. The majority of our midstream expenditures from 2007 to 2009 were related to development activities in the Barnett Shale, the Arkoma-Woodford Shale in southeastern Oklahoma, the Cana-Woodford Shale in western Oklahoma and Jackfish in Canada.

Net Repayments of Debt

Debt repayments in 2009 include the retirement of $177 million of 10.125% notes upon maturity in the fourth quarter.

During 2008, we repaid $1.5 billion in outstanding credit facility borrowings primarily with proceeds received from the sales of assets under our African divestiture program. Also during 2008, virtually all holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock owned by us. The debentures matured on August 15, 2008. In lieu of delivering our shares of Chevron common stock, we exercised our option to pay the exchanging debenture holders cash totaling $1.0 billion. This amount included the retirement of debentures with a book value of $652 million and a $379 million payment of the related embedded derivative option.

During 2007, we repaid the $400 million 4.375% notes, which matured on October 1, 2007. Also during 2007, certain holders of exchangeable debentures exercised their option to exchange their debentures for shares of Chevron common stock prior to the debentures August 15, 2008 maturity date. In lieu of delivering shares of Chevron common stock, we exercised our option to pay the exchanging debenture holders an amount of cash equal to the market value of Chevron common stock. We paid $167 million in cash to exchangeable debenture holders who exercised their exchange rights. This amount included the retirement of debentures with a book value of $105 million and a $62 million payment of the related embedded derivative option.

Repurchases of Common Stock

During 2008 and 2007, we repurchased 10.6 million shares at a total cost of $1.0 billion, or an average of $93.76 per share, under approved repurchase programs. No shares were repurchased in 2009. The following table summarizes our repurchases under approved plans during 2008 and 2007 (amounts and shares in millions). Both programs expired on December 31, 2009.

	2008			2007		
Repurchase Program	**Amount**	**Shares**	**Per Share**	**Amount**	**Shares**	**Per Share**
Annual program	$ 178	2.0	$ 87.83	$		$
2007 program	487	4.5	$ 109.25	326	4.1	$ 79.80
Totals	$ 665	6.5	$ 102.56	$ 326	4.1	$ 79.80

Redemption of Preferred Stock

On June 20, 2008, we redeemed all 1.5 million outstanding shares of our 6.49% Series A cumulative preferred stock. Each share of preferred stock was redeemed for cash at a redemption price of $100 per share, plus accrued and unpaid dividends up to the redemption date.

Dividends

Our common stock dividends were $284 million (or a quarterly rate of $0.16 per share) in both 2009 and 2008, and $249 million (or a quarterly rate of $0.14) in 2007. Common dividends increased from 2007 to 2008 primarily due to the higher quarterly dividend rates.

We also paid $5 million of preferred stock dividends in 2008 and $10 million of preferred stock dividends in 2007. The decrease in the preferred dividends in 2008 was due to the redemption of our preferred stock in the second quarter of 2008.

Liquidity

Historically, our primary source of capital and liquidity has been operating cash flow. Additionally, we maintain revolving lines 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, as well as our automatically effective registration statement on Form S-3ASR filed with the SEC. This registration statement can be used to offer short-term and long-term debt securities. In 2010, another major source of liquidity will be proceeds from the sales of our offshore operations, which we estimate will range from $4.5 billion to $7.5 billion after taxes. We expect the combination of these sources of capital will be adequate to fund future capital expenditures, debt repayments and other contractual commitments as discussed later in this section.

Operating Cash Flow

Our operating cash flow is sensitive to many variables, the most volatile of which is pricing of the oil, natural gas and NGLs we produce. Due to sharp declines in commodity prices, our operating cash flow decreased approximately 50% to $4.7 billion in 2009 as compared to 2008. In spite of the recent commodity price declines, we expect operating cash flow will continue to be a primary source of liquidity, and we will need to manage our capital expenditures and other cash uses accordingly. However, as a result of depressed commodity prices, debt borrowings have been a significant source of liquidity during 2009. During 2009, our net borrowings of long-term debt and commercial paper totaled $1.6 billion. We anticipate utilizing commercial paper borrowings as needed to supplement operating cash flow in 2010. As the offshore divestiture transactions close, we anticipate using a portion of the proceeds to repay our commercial paper borrowings.

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Commodity Prices Prices for oil, gas and NGLs 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, which are difficult to predict, create volatility in oil, gas and NGL prices and are beyond our control. We expect this volatility to continue throughout 2010.

To mitigate some of the risk inherent in prices, we have utilized various price swap, fixed-price physical delivery and price collar contracts to set minimum and maximum prices on our 2010 production. As of February 15, 2010 approximately 65% of our estimated 2010 oil production is subject to price collars and approximately 54% of our estimated 2010 gas production is subject to price collars, price swaps and fixed-price physicals. We also have basis swaps associated with 0.2 Bcf per day of our 2010 gas production.

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. However, the inverse is also true during periods of depressed commodity prices such as what we are currently experiencing.

Interest Rates Our operating cash flow can also be sensitive to interest rate fluctuations. As of February 15, 2010, we had total debt of $7.1 billion with an overall weighted average borrowing rate of 5.93%. To manage our exposure to interest rate volatility, we have interest rate swap instruments with a total notional amount of $1.85 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect, based upon us paying a fixed rate and receiving a floating rate. Including the effects of these swaps, the weighted-average interest rate related to our fixed-rate debt was 5.36% as of February 15, 2010.

Credit Losses Our operating cash flow is also exposed to credit risk in a variety of ways. We are exposed to the credit risk of the customers who purchase our oil, gas and NGL production. We are also exposed to credit risk related to the collection of receivables from our joint-interest partners for their proportionate share of expenditures made on projects we operate. We are also exposed to the credit risk of counterparties to our derivative financial contracts as discussed previously in this report.

The recent deterioration of the global financial and capital markets, combined with the drop in commodity prices, has increased our credit risk exposure. However, we utilize a variety of mechanisms to limit our exposure to the credit risks of our customers, partners and counterparties. Such mechanisms include, under certain conditions, posting of letters of credit, prepayment requirements and collateral posting requirements.

Credit Availability

We have two revolving lines of credit and a commercial paper program which we can access to provide liquidity.

We have a $2.65 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility). The maturity date for $2.15 billion of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $0.5 billion is April 7, 2012. All amounts outstanding will be due and payable on the respective maturity dates 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. The Senior Credit Facility includes a 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 February 15, 2010, there were no borrowings under the Senior Credit Facility.

We also have a $700 million 364-day, syndicated, unsecured revolving senior credit facility (the Short-Term Facility) that matures on November 2, 2010. On the maturity date, all amounts outstanding will be due

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and payable at that time. Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally based on LIBOR or the prime rate. As of February 15, 2010, there were no borrowings under the Short-Term Facility.

We also have access to short-term credit under our commercial paper program. Total borrowings under the commercial paper program may not exceed $2.85 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility or the Short-Term Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between one 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 February 15, 2010, we had $1.3 billion of commercial paper debt outstanding at an average rate of 0.25%.

The Senior Credit Facility and Short-Term Facility contain 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 the consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2009, we were in compliance with this covenant. Our debt-to-capitalization ratio at December 31, 2009, as calculated pursuant to the terms of the agreement, was 20.5%.

Our access to funds from the Senior Credit Facility and Short-Term 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 credit facilities include covenants that require us to report a condition or event having a material adverse effect, the obligation of the banks to fund the credit facilities is not conditioned on the absence of a material adverse effect.

The following schedule summarizes the capacity of our credit facilities by maturity date, as well as our available capacity as of February 15, 2010 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Short-Term Facility November 2, 2010 maturity	700
Total credit facilities	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	1,257
Outstanding letters of credit	88
Total available capacity	$ 2,005

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 stable outlook by both Fitch and Standard & Poor s, and Baa1 with a stable outlook by Moody s.

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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 from LIBOR plus 35 basis points to a new rate of LIBOR plus 45 basis points. A ratings downgrade could also adversely impact our ability to economically access debt markets in the future. As of December 31, 2009, we were not aware of any potential ratings downgrades being contemplated by the rating agencies.

Capital Expenditures

Our 2010 capital expenditures are expected to range from $6.0 billion to $6.8 billion, including amounts related to our discontinued operations. To a certain degree, the ultimate timing of these capital expenditures is within our control. Therefore, if oil and gas prices fluctuate from current estimates, we could choose to defer a portion of these planned 2010 capital expenditures until later periods, or accelerate capital expenditures planned for periods beyond 2010 to achieve the desired balance between sources and uses of liquidity. The amount and timing of the planned offshore asset divestitures in 2010 could also result in acceleration of capital spending on our North American Onshore opportunities. Based upon current price expectations for 2010 and the commodity hedging contracts we have in place, we anticipate having adequate capital resources to fund our 2010 capital expenditures.

Common Stock Repurchase Programs

All of our common stock repurchase programs expired on December 31, 2009. None of our programs were extended to 2010.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2009, 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)		
North American Onshore:					
Debt(1)	$ 7,267	$ 1,432	$ 2,110	$ 500	$ 3,225
Interest expense(2)	4,998	406	666	508	3,418
Drilling and facility obligations(3)	1,136	659	395	81	1
Firm transportation agreements(4)	1,939	298	508	419	714
Asset retirement obligations(5)	1,068	44	115	150	759
Lease obligations(6)	347	57	94	49	147
Other(7)	518	129	128	57	204
Total North American Onshore	17,273	3,025	4,016	1,764	8,468
Offshore:					
Drilling and facility obligations(3)	2,113	955	775	383	

Asset retirement obligations(5)	554	51	141	61	301
Lease obligations(6)	602	121	182	176	123
Total Offshore	3,269	1,127	1,098	620	424
Grand Total	$ 20,542	$ 4,152	$ 5,114	$ 2,384	$ 8,892

(1) Debt amounts represent scheduled maturities of our debt obligations at December 31, 2009, excluding $12 million of net premiums included in the carrying value of debt.

(2) Interest expense related to our fixed-rate debt represents the scheduled cash payments. Interest related to our variable-rate commercial paper borrowings was estimated based upon expected future interest rates as of December 31, 2009.

(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 $2.1 billion of offshore obligations is $1.4 billion that relates to long-term contracts for three deepwater drilling rigs and certain other contracts for offshore drilling and facility obligations in which drilling or facilities construction has not commenced. The $1.4 billion represents the gross commitment under these contracts. Our ultimate payment for these commitments will be reduced by any amounts billed to our working interest partners until we sell the associated offshore properties. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

Additionally, our commitment under these contracts may be further reduced if the buyers of our offshore assets assume all or a portion of the obligations. If the buyers do not assume these obligations, we will attempt to sublease the rigs to reduce our commitment. However, if the buyers do not assume the obligations and we are not able to sublease the rigs, we would be contractually committed to the amounts related to the remaining lease periods.

(4) 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.

(5) Asset retirement obligations represent estimated discounted costs for future dismantlement, abandonment and rehabilitation costs. These obligations are recorded as liabilities on our December 31, 2009 balance sheet.

(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 three FPSO s that are related to the Panyu project offshore China, the Polvo project offshore Brazil and the Cascade project offshore the Gulf of Mexico. The Panyu FPSO lease term expires in 2018. The Polvo FPSO lease term expires in 2014. The Cascade FPSO lease term expires in 2015. We expect the eventual buyers of these offshore assets will assume the FPSO leases. However, the amounts in the table reflect our full commitments under the leases.

(7) These amounts include $272 million related to uncertain tax positions. Expected pension funding obligations have not been included in this table, but are presented and discussed in the section immediately below.

Pension Funding and Estimates

Funded Status As compared to the projected benefit obligation, our qualified and nonqualified defined benefit plans were underfunded by $448 million and $501 million at December 31, 2009 and 2008,

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respectively. A detailed reconciliation of the 2009 changes to our underfunded status is included in Note 8 to the accompanying consolidated financial statements. Of the $448 million underfunded status at the end of 2009, $215 million is attributable to various nonqualified defined benefit plans that have no plan assets. However, we have established certain trusts to fund the benefit obligations of such nonqualified plans. As of December 31, 2009, these trusts had investments with a fair value of $39 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 underfunded by $164 million at December 31, 2009. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels.

Our funding policy regarding the qualified defined benefit plans is to contribute the amounts necessary for the plans assets to approximately equal the present value of benefits earned by the participants, as calculated in accordance with the provisions of the Pension Protection Act. While we did have investment gains in 2009, the investment losses experienced during 2008 significantly reduced the value of our plans assets. We estimate we will contribute approximately $25 million to our qualified pension plans during 2010. However, actual contributions may be different than this amount.

Our funding policy regarding the nonqualified defined benefit plans is to supplement as needed the amounts accumulated in the related trusts with available cash and cash equivalents.

Pension Estimate Assumptions Our pension expense is recognized on an accrual basis over employees approximate service periods and is impacted by funding decisions or requirements. We recognized expense for our defined benefit pension plans of $119 million, $61 million and $41 million in 2009, 2008 and 2007, respectively. We estimate that our pension expense will approximate $85 million in 2010. Should our actual 2010 contributions to qualified and nonqualified plans vary significantly from our current estimate of $34 million, our actual 2010 pension expense could vary from this estimate.

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 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 7.18% and 8.40% at December 31, 2009 and 2008, respectively. We developed these expected long-term rate of return assumptions by evaluating input from external consultants and economists as well as long-term inflation assumptions. The expected long-term rate of return on plan assets is based on a target allocation of investment types in such assets. At December 31, 2009, the target allocations for plan assets were 47.5% for equity securities, 40% for fixed-income securities and 12.5% for other investment types. Equity securities consist of investments in large capitalization and small capitalization companies, both domestic and international. Fixed-income securities include corporate bonds of investment-grade companies from diverse industries, United States Treasury obligations and asset-backed securities. Other investment types include short-term investment funds and a hedge fund of funds. 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 would increase the expected 2010 pension expense by $5 million.

We discounted our future pension obligations using a weighted average rate of 6.00% at December 31, 2009 and 2008. The discount rate is determined at the end of each year based on the rate at which obligations could be effectively settled, considering the expected timing of future cash flows related to the plans. 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 would increase our pension liability at December 31, 2009, by $32 million, and increase estimated 2010 pension expense by $4 million.

At December 31, 2009, we had net actuarial losses of $334 million, which will be recognized as a component of pension expense in future years. These losses are primarily due to investment losses on plan assets in 2008, reductions in the discount rate since 2001 and increases in participant wages. We estimate that approximately $27 million and $23 million of the unrecognized actuarial losses will be included in pension expense in 2010 and 2011, respectively. The $27 million estimated to be recognized in 2010 is a component of the total estimated 2010 pension expense of $85 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.

Contingencies and Legal Matters

For a detailed discussion of contingencies and legal matters, see Note 10 of the accompanying consolidated financial statements.

Critical Accounting Policies and Estimates

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

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regard to estimates used. Our critical accounting policies and significant judgments and estimates related to those policies are described below. We have reviewed these critical accounting policies with the Audit Committee of our 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. The ceiling limitation is imposed separately for each country in which we have oil and gas properties. 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, 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, 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 22 of the accompanying consolidated financial statements for a summary of the amount of our reserves that are prepared or audited by outside petroleum consultants.

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 performance revisions to our reserve estimates, which have been both increases and decreases in individual years, have averaged less than 2% of the previous year s estimate. However, there can be no assurance that more significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of DD&A.

While the quantities of proved reserves require substantial judgment, the associated prices of oil, 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 future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of each quarterly period. Costs included in future net revenues are determined in a similar manner. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. In calculating the ceiling, we adjust the end-of-period price by the effect of derivative contracts in place that qualify for hedge accounting treatment. This adjustment requires little judgment as the calculated average price is adjusted using the contract prices for such hedges. None of our outstanding derivative contracts at December 31, 2009 qualified for hedge accounting treatment.

Because the ceiling calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value is not indicative of the true fair value of the reserves. Oil and gas prices have historically been cyclical and, for any particular 12-month period, can be either higher or lower than our long-term price forecast, which is a more appropriate input for estimating fair value. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Because of the volatile nature of oil and gas prices, it is not possible to predict the timing or magnitude of full cost writedowns.

Derivative Financial Instruments

Policy Description

We periodically enter into derivative financial instruments with respect to a portion of our oil and gas production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Our oil and gas derivative financial instruments include financial price swaps, basis swaps and costless price collars. Additionally, we periodically enter into interest rate swaps to manage our exposure to interest rate volatility. Under the terms of certain of our interest-rate swaps, we receive a fixed rate and pay a variable rate on a total notional amount. The remainder of our swaps represent forward starting swaps, under which we will pay a fixed rate and receive a floating rate on a total notional amount.

All derivative financial instruments are recognized at their current fair value as either assets or liabilities in the balance sheet. Changes in the fair value of these 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. Cash settlements with counterparties to our derivative financial instruments also increase or decrease earnings at the time of the settlement.

A derivative financial 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 a business combination or other transaction that 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. For derivative financial instruments held during 2009, 2008 and 2007, we chose not to meet the necessary criteria to qualify our derivative financial instruments for hedge accounting treatment.

Judgments and Assumptions

The estimates of the fair values of our derivative instruments require substantial judgment. We estimate the fair values of our oil and gas derivative financial instruments primarily by using internal discounted cash flow calculations. The most significant variable to our cash flow calculations is our estimate of future commodity prices. We base our estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Another key input to our cash flow calculations is our estimate of volatility for these forward curves, which we base primarily upon implied volatility. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. These pricing and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward prices and regional price differentials.

We estimate the fair values of our interest rate swap financial instruments primarily by using internal discounted cash flow calculations based upon forward interest-rate yields. The most significant variable to our cash flow calculations is our estimate of future interest rate yields. We base our estimate of future yields upon our own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by third parties. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted using LIBOR and money market futures rates for the first year and money market futures and swap rates thereafter. These yield and discounting variables are sensitive to the period of the contract and market volatility as well as changes in forward interest rate yields.

We periodically validate our valuation techniques by comparing our internally generated fair value estimates with those obtained from contract counterparties and/or brokers.

In spite of the recent turmoil in the financial markets, counterparty credit risk has not had a significant effect on our cash flow calculations and derivative valuations. This is primarily the result of two factors. First, we have mitigated our exposure to any single counterparty by contracting with numerous counterparties. Our commodity derivative contracts are held with twelve separate counterparties, and our interest rate derivative contracts are held with seven separate counterparties. Second, our derivative contracts generally require cash collateral to be posted if either our or the counterparty s credit rating falls below investment grade . The mark-to-market exposure threshold for collateral posting decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of December 31, 2009, the credit ratings of all our counterparties were investment grade.

Because we have chosen not to qualify our derivatives for hedge accounting treatment, changes in the fair values of derivatives can have a significant impact on our results of operations. Generally, changes in derivative fair values 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 can 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

From our beginning as a public company in 1988 through 2003, we grew substantially through acquisitions of other oil and gas companies. Most of these acquisitions have been accounted for using the purchase method of accounting. Current accounting pronouncements require the purchase method to be used to account for any future acquisitions.

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, 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, 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 dictates the use of prices that are not representative of future prices. By contrast, the fair value of reserves acquired in a business combination must be based on our estimates of future oil, 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 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 acquisition of Mitchell Energy & Development Corp., 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 serve 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 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 Item 7. 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.

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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 performance revisions to our reserve estimates have averaged less than 2%. As discussed in the preceding paragraphs, there are numerous estimates in addition to reserve quantity estimates that are involved in determining the fair value of oil and gas properties acquired in a business combination. The inter-relationship of these estimates makes it impractical to provide additional quantitative analyses of the effects of changes in these estimates.

Valuation of Goodwill

Policy Description

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.

Judgments and Assumptions

The annual impairment test, which we conduct as of October 31 each year, requires us to estimate the fair values of our own assets and liabilities. Because quoted market prices are not available for our reporting units, the fair values of the reporting units are estimated 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. At October 31, 2009, the fair values of our United States and Canadian reporting units were more than double their related carrying values. This excess largely results from the reductions of carrying value that we recognized in 2008 and 2009 due to full cost ceiling limitations, which are not representative of the fair values of our oil and gas properties. Excluding the effects of these reductions, the fair values of our United States and Canadian reporting units exceeded the carrying values by approximately 40% and 80%, respectively.

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.

Forward-Looking Estimates

We are providing our 2010 forward-looking estimates in the following discussion. These estimates are based on our examination of historical operating trends, the information used to prepare our December 31, 2009 reserve reports and other data in our possession or available from third parties. The forward-looking estimates in this discussion were prepared assuming demand, curtailment, producibility and general market conditions for our oil, gas and NGLs during 2010 will be substantially similar to those that existed in 2009, 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 an estimated average 2010 exchange rate of $0.95 U.S. dollar to $1.00 Canadian dollar.

We plan to strategically reposition Devon by divesting our U.S. Offshore and International assets. We have entered into agreements to sell our interests in the Cascade, Jack and St. Malo properties in the Gulf of

Mexico. The following estimates assume these transactions close on the expected dates during the first quarter of 2010. Although we expect to complete the remainder of the divestitures throughout 2010, all estimates presented assume the remaining divestitures close at the end of 2010.

Operating Items

Oil, Gas and NGL Production

Set forth below are our estimates of oil, gas and NGL production for 2010. We estimate that our combined oil, gas and NGL production will total approximately 231 to 235 MMBoe. The following estimates for oil, gas and NGL production are calculated at the midpoint of the estimated range for total production.

	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)
U.S. Onshore	13	692	28	156
Canada	28	204	3	65
North American Onshore	41	896	31	221
U.S. Offshore	4	46		12
Total	45	942	31	233

Oil and Gas Prices

We expect our 2010 average prices for the oil and gas production from each of our operating areas to differ from the NYMEX price as set forth in the following table. The expected ranges for prices are exclusive of the anticipated effects of the financial contracts presented in the Commodity Price Risk Management section below.

The NYMEX price for oil is determined using the monthly average of settled prices on each trading day for benchmark West Texas Intermediate crude oil delivered at Cushing, Oklahoma. The NYMEX price for gas is determined using the first-of-month South Louisiana Henry Hub price index as published monthly in Inside FERC.

	Expected Range of Prices as a % of NYMEX Price	
	Oil	Gas
U.S. Onshore	90% to 100%	75% to 85%
Canada	65% to 75%	85% to 95%
North American Onshore	72% to 82%	77% to 87%
U.S. Offshore	95% to 105%	100% to 110%

Commodity Price Risk Management

From time to time, we enter into NYMEX related financial commodity collar, price swap and basis swap contracts. Such contracts are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility.

Although these financial contracts do not relate to specific production from our operating areas, they will affect our overall revenues, earnings and cash flow in 2010.

As of February 15, 2010, our financial commodity contracts pertaining to 2010 consisted of oil and gas price collars, gas price swaps and gas basis swaps. The key terms of these contracts are presented in the following tables.

	Gas Price Swaps	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
Total year	1,265,000	$ 6.16

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		Gas Basis Swaps	
Period	Index	Volume (MMBtu/d)	Weighted Average Differential to Henry Hub ($/MMBtu)
Total year	AECO	150,000	$ 0.33
Total year	CIG	70,000	$ 0.37

		Gas Price Collars			
		Floor Price		Ceiling Price	
Period	Volume (MMBtu/d)	Floor Range ($/MMBtu/d)	Weighted Average Price ($/MMBtu/d)	Ceiling Range ($/MMBtu/d)	Weighted Average Price ($/MMBtu/d)
First Quarter	70,000	$ 5.40 - $5.40	$ 5.40	$ 6.01 - $6.14	$ 6.06
Second Quarter	95,000	$ 5.50 - $5.50	$ 5.50	$ 6.80 - $7.10	$ 6.94
Third Quarter	95,000	$ 5.50 - $5.50	$ 5.50	$ 6.80 - $7.10	$ 6.94
Fourth Quarter	95,000	$ 5.50 - $5.50	$ 5.50	$ 6.80 - $7.10	$ 6.94
Total year	88,836	$ 5.40 - $5.50	$ 5.48	$ 6.01 - $7.10	$ 6.76

		Oil Price Collars			
		Floor Price		Ceiling Price	
Period	Volume (Bbls/d)	Floor Range ($/Bbl)	Weighted Average Price ($/Bbl)	Ceiling Range ($/Bbl)	Weighted Average Price ($/Bbl)
Total year	79,000	$ 65.00 - $70.00	$ 67.47	$ 90.35 - $103.30	$ 96.48

To the extent that monthly NYMEX prices or differentials on certain regional indexes in 2010 are outside of the ranges established by the collars or differ from those established by the swaps, we and the counterparties to the contracts will cash-settle the difference. Such settlements will either increase or decrease our revenues for the period. Also, we will mark-to-market the contracts based on their fair values throughout 2010. Changes in the contracts fair values will also be recorded as increases or decreases to our revenues. The expected ranges of our realized prices as a percentage of NYMEX prices, which are presented earlier in this report, do not include any estimates of the impact on our prices from monthly settlements or changes in the fair values of our price collars and swaps.

Marketing and Midstream Revenues and Expenses

Marketing and midstream revenues and expenses are derived primarily from our gas processing plants and gas pipeline systems. 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 gas and NGLs, provisions of contractual agreements and the amount of repair and maintenance activity required to maintain anticipated processing levels and pipeline throughput volumes.

These factors increase the uncertainty inherent in estimating future marketing and midstream revenues and expenses. Given these uncertainties, we estimate that our 2010 marketing and midstream operating profit will be between $450 million and $525 million. We estimate that marketing and midstream revenues will be between $1.850 billion and $2.125 billion, and marketing and midstream expenses will be between $1.400 billion and $1.600 billion.

Lease Operating Expenses

These expenses, which include transportation costs, 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. Oil, 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 expect that our 2010 lease operating expenses will be between $1.74 billion and $1.90 billion. This estimated range includes $1.58 billion to $1.72 billion related to our North American Onshore business and $0.16 to $0.18 billion associated with our U.S. Offshore operations.

Taxes Other Than Income Taxes

Our taxes other than income taxes primarily consist of production taxes and ad valorem taxes that relate to our U.S. Onshore properties and are assessed by various government agencies. Production taxes are based on a percentage of production revenues that varies by property and government jurisdiction. Ad valorem taxes generally are based on property values as determined by the government agency assessing the tax. Over time, a certain property s assessed value will increase or decrease due to changes in commodity sales prices, production volumes and proved reserves. Therefore, ad valorem taxes will generally move in the same direction as our oil, gas and NGL sales but in a less predictable manner compared to production taxes. Additionally, both production and ad valorem taxes will increase or decrease due to changes in the rates assessed by the government agencies.

Given these uncertainties, we estimate that our taxes other than income taxes for 2010 will be between 4.50% and 5.50% of total oil, gas and NGL sales. We estimate our 2010 taxes other than income taxes for our North American Onshore operations will range from 4.75% to 5.75% of revenues. We estimate the U.S. Offshore rates will range from 1.00% to 2.00% of revenues.

Depreciation, Depletion and Amortization (DD&A)

Our 2010 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 2010 compared to the costs incurred for such efforts, revisions to our year-end 2009 reserve estimates that, based on prior experience, are likely to be made during 2010, as well as reductions of carrying value resulting from full cost ceiling tests.

Given these uncertainties, we estimate that our oil and gas property related DD&A rate will be between $7.60 per Boe and $8.10 per Boe. Based on these DD&A rates and the production estimates set forth earlier, oil and gas property related DD&A expense for 2010 is expected to be between $1.77 billion and $1.89 billion.

For our North American Onshore assets, we estimate the DD&A rate will range from $7.65 to $8.15 per Boe, resulting in estimated DD&A expense of $1.69 billion to $1.80 billion. Our U.S. Offshore DD&A rate is estimated to be between $6.75 and $7.25 per Boe, resulting in estimated DD&A expense of $0.08 billion to $0.09 billion.

Additionally, we expect that our depreciation and amortization expense related to non-oil and gas property fixed assets will total between $270 million and $300 million in 2010. This estimate relates entirely to our North American Onshore assets.

Accretion of Asset Retirement Obligation

Accretion of asset retirement obligation in 2010 is expected to be between $95 million and $105 million. This estimated range includes $70 million to $80 million related to our North American Onshore business and $25 million associated with our U.S. Offshore operations.

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, we estimate our G&A for 2010 will be between $580 million and $620 million. This estimate includes approximately $115 million of non-cash, share-based compensation, net of related capitalization in accordance with the full cost method of accounting for oil and gas properties.

Restructuring Costs

In conjunction with the planned 2010 asset divestitures, we estimate we will incur certain one-time restructuring costs totaling between $203 million and $273 million. Such costs estimates consist of employee severance and termination costs, contract termination costs and other associated costs. We recognized $153 million of employee severance costs during the fourth quarter of 2009. We expect the majority of the remaining restructuring costs, including any revisions to the fourth quarter 2009 employee severance costs, will be recognized during 2010.

Reduction of Carrying Value of Oil and Gas Properties

Due to the volatile nature of oil and gas prices, it is not possible to predict whether we will incur full cost writedowns in 2010.

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 2010 from sales of oil, gas and NGLs and the resulting cash flow. This increases the margin of error inherent in estimating future outstanding debt balances and related interest expense. Other factors that affect outstanding debt balances and related interest expense, such as the amount and timing of capital expenditures are generally within our control.

As of February 15, 2010, we had total debt of $7.1 billion. This included $5.8 billion of fixed-rate debt and $1.3 billion of variable-rate commercial paper borrowings. The fixed-rate debt bears interest at an overall weighted average rate of 7.2%. The commercial paper borrowings bear interest at variable rates 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 February 15, 2010, the weighted average variable rate for our commercial paper borrowings was 0.25%. Additionally, any future borrowings under our credit facilities would bear interest at various fixed-rate options for periods up to twelve months and are generally less than the prime rate.

Based on the factors above, we expect our 2010 interest expense to be between $325 million and $365 million. The estimated interest expense is exclusive of the anticipated effects of the interest rate swap contracts presented in the Interest Rate Risk Management section below.

The 2010 interest expense estimate above is comprised of three primary components interest related to outstanding debt, fees and issuance costs, and capitalized interest. We expect the interest expense in 2010 related to our fixed-rate and floating-rate debt, including net accretion of related discounts, to be between $395 million and $435 million. We expect the interest expense in 2010 related to facility and agency fees, amortization of debt issuance costs and other miscellaneous items not related to outstanding debt balances to be between $10 million and $20 million. We also expect to capitalize between $80 million and $90 million of interest during 2010.

Interest Rate Risk Management

From time to time, we enter into interest rate swaps. Such contracts are used to manage our exposure to interest rate volatility.

As of February 15, 2010, our interest rate swaps pertaining to 2010 consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The key terms of these contracts are presented in the following table.

Notional (In millions)		Fixed Rate Received	Variable Rate Paid	Expiration
$	300	4.30%	Six month LIBOR	July 18, 2011
$	100	1.90%	Federal funds rate	August 3, 2012
$	500	3.90%	Federal funds rate	July 18, 2013
$	250	3.85%	Federal funds rate	July 22, 2013
$	1,150	3.82%		

Income Taxes

Our financial income tax rate in 2010 will vary materially depending on the actual amount of financial pre-tax earnings. The tax rate for 2010 will be significantly affected by the proportional share of consolidated pre-tax earnings generated by our United States and Canadian operations due to the different tax rates of each country. Also, certain tax deductions and credits will have a fixed impact on 2010 income tax expense regardless of the level of pre-tax earnings that are produced. Additionally, significant changes in estimated capital expenditures, production levels of oil, gas and NGLs, the prices of such products, marketing and midstream revenues, or any of the various expense items could materially alter the effect of these tax deductions and credits on 2010 financial income tax rates.

Given the uncertainty of pre-tax earnings, we expect that our total financial income tax rate in 2010 will be between 20% and 40%. The current income tax rate is expected to be between 10% and 20%. The deferred income tax rate is expected to be between 10% and 20%. These ranges do not include the impact of current and deferred income taxes that will be recognized upon the completion of the 2010 asset divestitures.

Discontinued Operations

The following table shows the estimates for 2010 production, pricing, expenses and capital associated with our discontinued International operations for 2010. These estimates assume the sales will occur at the end of 2010. Pursuant to accounting rules for discontinued operations, the International assets will not be subject to DD&A during 2010.

	Low	High
	($ in millions, except per Boe)	
Oil production (MMBbls)	14	16
Average oil price as a % of NYMEX	90%	100%
LOE	$ 190	$ 210
Taxes other than income taxes as % of revenue	10.25%	11.25%
Accretion of asset retirement obligation	$ 5	$ 5

Income tax rates:		
Current	20%	30%
Deferred	(5)%	%
Total	15%	30%
Development capital	$ 220	$ 260
Exploration capital	$ 240	$ 280
Total development & exploration	$ 460	$ 540
Other capital	$ 80	$ 90

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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 forecast, 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, 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 2010 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 ranges for drilling, development and facilities expenditures by geographic area. Development capital includes development activity related to reserves classified as proved and 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	Canada	North American Onshore (In millions)	U.S. Offshore	Total
Development capital	$ 2,210-$2,470	$ 1,010-$1,140	$ 3,220-$3,610	$ 420-$500	$ 3,640-$4,110
Exploration capital	$ 520-$560	$ 20-$30	$ 540-$590	$ 100-$120	$ 640-$710
Total	$ 2,730-$3,030	$ 1,030-$1,170	$ 3,760-$4,200	$ 520-$620	$ 4,280-$4,820

In addition to the above expenditures for drilling, development and facilities, we expect to capitalize between $330 million and $350 million of G&A expenses in accordance with the full cost method of accounting and to capitalize between $45 million and $55 million of interest. We also expect to pay between $80 million and $90 million for plugging and abandonment charges. Additionally, we expect to spend between $380 million and $430 million on our marketing and midstream assets, which primarily include our oil pipelines, gas processing plants, and gas pipeline systems. We expect to spend between $385 million and $435 million for corporate and other fixed assets.

Other Cash Uses

Our management expects the policy of paying a quarterly common stock dividend to continue. With the current $0.16 per share quarterly dividend rate and 447 million shares of common stock outstanding as of December 31, 2009, dividends are expected to approximate $286 million.

Capital Resources and Liquidity

Our estimated 2010 cash uses, including our capital activities, are expected to be funded primarily through a combination of our existing cash balances and operating cash flow. Another major source of liquidity will be proceeds from the divestiture of our offshore operations, which we estimate will range from $4.5 billion to $7.5 billion after taxes. The amount of operating cash flow to be generated during 2010 is uncertain due to the factors affecting revenues and expenses as previously cited. The amount of divestiture proceeds we ultimately receive is also uncertain. However, we expect our combined capital resources will be adequate to fund our anticipated capital expenditures and other cash uses for 2010. Additionally, we can borrow commercial paper or access our lines of credit, which had an available capacity of approximately $2.0 billion as of February 15, 2010, to fund planned or additional capital activities.

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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 following 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 gas and NGL production. Pricing for oil, gas and NGL production has been volatile and unpredictable for several years. See Item 1A. Risk Factors. Consequently, we periodically enter into financial hedging activities with respect to a portion of our oil and gas production through various financial transactions that hedge the future prices received. These transactions include financial price swaps, basis swaps and costless price collars.

Based on gas price contracts in place as of December 31, 2009, we have approximately 1.3 Bcf per day of gas production in 2010 that is associated with price swaps or fixed-price contracts. This amount represents approximately 50% of our estimated 2010 gas production. As of December 31, 2009, we also have basis swaps associated with 0.2 Bcf per day of our 2010 gas production. All of the gas price swap contracts expire December 31, 2010. The key terms of our gas price contracts are presented in the following tables.

	2010 Gas Price Swaps	
Period	**Volume (MMBtu/d)**	**Weighted Average Price ($/MMBtu)**
Total year	1,265,000	$ 6.16

		2010 Gas Basis Swaps	
Period	**Index**	**Volume (MMBtu/d)**	**Weighted Average Differential to Henry Hub ($/MMBtu)**
Total year	AECO	150,000	$ 0.33
Total year	CIG	70,000	$ 0.37

Based on oil price collar contracts in place as of December 31, 2009, we have hedged 79,000 barrels of oil per day for 2010. This amount represents approximately 65% of our estimated 2010 oil production. The key terms of our oil collar contracts are presented in the following table.

		2010 Oil Price Collars			
		Floor Price		Ceiling Price	
Period	**Volume (Bbls/d)**	**Floor Range ($/Bbl)**	**Weighted Average Price ($/Bbl)**	**Ceiling Range ($/Bbl)**	**Weighted Average Price ($/Bbl)**
Total year	79,000	$ 65.00 - $70.00	$ 67.47	$ 90.35 - $103.30	$ 96.48

The fair values of our gas price and basis swaps and oil collars are largely determined by estimates of the forward curves of relevant oil and gas price indexes. At December 31, 2009, a 10% increase in these forward curves would have decreased the fair value of our gas price swaps by approximately $264 million. A 10% increase in the forward curves associated with our oil collars would have decreased the fair value of these instruments by approximately $108 million.

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Interest Rate Risk

At December 31, 2009, we had debt outstanding of $7.3 billion. Of this amount, $5.9 billion, or 80%, bears interest at fixed rates averaging 7.2%. Additionally, we had $1.4 billion of outstanding commercial paper, bearing interest at floating rates which averaged 0.29%.

As of December 31, 2009, our interest rate swaps consisted of instruments with a total notional amount of $1.85 billion. These consist of instruments with a notional amount of $1.15 billion in which we receive a fixed rate and pay a variable rate. The remaining instruments consist of forward starting swaps. Under the terms of the forward starting swaps, we will net settle these contracts in September 2011, or sooner should we elect. The net settlement amount will be based upon us paying a weighted-average fixed rate of 3.99% and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041. The key terms of these contracts are presented in the following tables.

Fixed-to-Floating Swaps

Notional (In millions)		Fixed Rate Received	Variable Rate Paid	Expiration
$	300	4.30%	Six month LIBOR	July 18, 2011
$	100	1.90%	Federal funds rate	August 3, 2012
$	500	3.90%	Federal funds rate	July 18, 2013
$	250	3.85%	Federal funds rate	July 22, 2013
$	1,150	3.82%		

Forward Starting Swaps

Notional (In millions)		Fixed Rate Paid	Variable Rate Received	Expiration
$	700	3.99%	Three month LIBOR	September 30, 2011

The fair values of our interest rate instruments are largely determined by estimates of the forward curves of the Federal Funds rate and LIBOR. At December 31, 2009, a 10% increase in these forward curves would have increased our net assets by approximately $46 million.

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, 2009 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.

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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, 2009 and 2008, and the related consolidated statements of operations, comprehensive (loss) income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2009. We also have audited Devon Energy Corporation s internal control over financial reporting as of December 31, 2009, 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 these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Annual Report contained in Item 9A. Controls and Procedures of Devon Energy Corporation s Annual Report on Form 10-K. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company s internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (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, 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, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also in our opinion, Devon Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on control criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

KPMG LLP

Oklahoma City, Oklahoma
February 24, 2010

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,			
	2009		2008	
	(In millions, except share data)			
ASSETS				
Current assets:				
Cash and cash equivalents	$	646	$	195
Accounts receivable		1,208		1,300
Derivative financial instruments, at fair value		211		282
Current assets held for sale		657		392
Other current assets		270		515
Total current assets		2,992		2,684
Property and equipment, at cost, based on the full cost method of accounting for oil and gas properties ($4,078 million and $4,248 million excluded from amortization in 2009 and 2008, respectively)		60,475		53,391
Less accumulated depreciation, depletion and amortization		41,708		31,360
Property and equipment, net		18,767		22,031
Goodwill		5,930		5,511
Long-term assets held for sale		1,250		1,128
Other long-term assets, including $246 million and $199 million at fair value in 2009 and 2008, respectively		747		554
Total assets	$	29,686	$	31,908
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable trade	$	1,137	$	1,612
Revenues and royalties due to others		486		490
Short-term debt		1,432		180
Current portion of asset retirement obligations, at fair value		95		138
Current liabilities associated with assets held for sale		234		365
Other current liabilities, including $38 million at fair value in 2009		418		350
Total current liabilities		3,802		3,135
Long-term debt		5,847		5,661
Asset retirement obligations, at fair value		1,418		1,249
Liabilities associated with assets held for sale, including $109 million and $98 million at fair value in 2009 and 2008, respectively		213		166
Other long-term liabilities		937		1,023

Deferred income taxes	1,899	3,614
Stockholders equity:		
Common stock of $0.10 par value. Authorized 1.0 billion shares;		
issued 446.7 million and 443.7 million shares in 2009 and 2008, respectively	45	44
Additional paid-in capital	6,527	6,257
Retained earnings	7,613	10,376
Accumulated other comprehensive income	1,385	383
Total stockholders equity	15,570	17,060
Commitments and contingencies (Note 10)		
Total liabilities and stockholders equity	$ 29,686	$ 31,908

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2009	2008	2007
	(In millions, except per share amounts)		
Revenues:			
Oil, gas and NGL sales	$ 6,097	$ 11,720	$ 8,225
Net gain (loss) on oil and gas derivative financial instruments	384	(154)	14
Marketing and midstream revenues	1,534	2,292	1,736
Total revenues	8,015	13,858	9,975
Expenses and other income, net:			
Lease operating expenses	1,670	1,851	1,532
Taxes other than income taxes	314	476	358
Marketing and midstream operating costs and expenses	1,022	1,611	1,217
Depreciation, depletion and amortization of oil and gas properties	1,832	2,948	2,412
Depreciation and amortization of non-oil and gas properties	276	255	201
Accretion of asset retirement obligations	91	80	70
General and administrative expenses	648	645	513
Restructuring costs	105		
Interest expense	349	329	430
Change in fair value of other financial instruments	(106)	149	(34)
Reduction of carrying value of oil and gas properties	6,408	9,891	
Other income, net	(68)	(217)	(51)
Total expenses and other income, net	12,541	18,018	6,648
Earnings (loss) from continuing operations before income taxes	(4,526)	(4,160)	3,327
Income tax expense (benefit):			
Current	241	441	235
Deferred	(2,014)	(1,562)	607
Total income tax expense (benefit)	(1,773)	(1,121)	842
Earnings (loss) from continuing operations	(2,753)	(3,039)	2,485
Discontinued operations:			
Earnings from discontinued operations before income taxes	322	1,258	1,593
Discontinued operations income tax expense	48	367	472
Earnings from discontinued operations	274	891	1,121
Net earnings (loss)	(2,479)	(2,148)	3,606
Preferred stock dividends		5	10

Net earnings (loss) applicable to common stockholders	$ (2,479)	$ (2,153)	$ 3,596
Basic net earnings (loss) per share:			
Basic earnings (loss) from continuing operations per share	$ (6.20)	$ (6.86)	$ 5.56
Basic earnings from discontinued operations per share	0.62	2.01	2.52
Basic net earnings (loss) per share	$ (5.58)	$ (4.85)	$ 8.08
Diluted net earnings (loss) per share:			
Diluted earnings (loss) from continuing operations per share	$ (6.20)	$ (6.86)	$ 5.50
Diluted earnings from discontinued operations per share	0.62	2.01	2.50
Diluted net earnings (loss) per share	$ (5.58)	$ (4.85)	$ 8.00

See accompanying notes to consolidated financial statements.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

	Year Ended December 31,		
	2009	2008	2007
		(In millions)	
Net earnings (loss)	$ (2,479)	$ (2,148)	$ 3,606
Foreign currency translation:			
Change in cumulative translation adjustment	993	(1,960)	1,389
Foreign currency translation income tax benefit (expense)	(62)	79	(42)
Foreign currency translation total	931	(1,881)	1,347
Pension and postretirement benefit plans:			
Net actuarial gain (loss) and prior service cost arising in current year	59	(239)	(90)
Recognition of net actuarial loss and prior service cost in net earnings (loss)	54	18	14
Curtailment of pension benefits			16
Pension and postretirement benefit plans income tax benefit (expense)	(42)	80	23
Pension and postretirement benefit plans total	71	(141)	(37)
Reclassification adjustment for realized gains included in net earnings			(1)
Other comprehensive earnings (loss), net of tax	1,002	(2,022)	1,309
Comprehensive income (loss)	$ (1,477)	$ (4,170)	$ 4,915

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, 2006	$ 1	444	$ 44	$ 6,840	$ 9,114	$ 1,444	$ (1)	$ 17,442
Net earnings (loss)					3,606			3,606
Other comprehensive earnings (loss), net of tax						1,309		1,309
Other financial instruments					364	(364)		
Uncertain income tax positions					(11)			(11)
Pension and postretirement benefit plans					(1)	16		15
Stock option exercises		3	1	90				91
Restricted stock grants, net of cancellations		2						
Common stock repurchased		(5)					(362)	(362)
Common stock retired			(1)	(362)			363	
Common stock dividends					(249)			(249)
Preferred stock dividends					(10)			(10)
Share-based compensation				131				131
Share-based compensation tax benefits				44				44
Balance as of December 31, 2007	1	444	44	6,743	12,813	2,405		22,006
Net earnings (loss)					(2,148)			(2,148)
Other comprehensive earnings (loss), net of tax						(2,022)		(2,022)
Stock option exercises		4	1	123			(8)	116
Restricted stock grants, net of cancellations		3						
Common stock repurchased		(7)					(709)	(709)
Common stock retired			(1)	(716)			717	
Redemption of preferred stock	(1)			(149)				(150)
Common stock dividends					(284)			(284)
Preferred stock dividends					(5)			(5)
Share-based compensation				196				196
				60				60

Share-based compensation tax benefits							
Balance as of December 31, 2008	$ 444	44	6,257	10,376	383		17,060
Net earnings (loss)				(2,479)			(2,479)
Other comprehensive earnings (loss), net of tax					1,002		1,002
Stock option exercises	1	1	47			(5)	43
Restricted stock grants, net of cancellations	2						
Common stock repurchased						(40)	(40)
Common stock retired			(45)			45	
Common stock dividends				(284)			(284)
Share-based compensation			260				260
Share-based compensation tax benefits			8				8
Balance as of December 31, 2009	447	$ 45	$ 6,527	$ 7,613	$ 1,385	$	$ 15,570

See accompanying notes to consolidated financial statements.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Cash flows from operating activities:			
Net earnings (loss)	$ (2,479)	$ (2,148)	$ 3,606
Net earnings from discontinued operations	(274)	(891)	(1,121)
Adjustments to reconcile earnings (loss) from continuing operations to net cash provided by operating activities:			
Depreciation, depletion and amortization	2,108	3,203	2,613
Deferred income tax expense (benefit)	(2,014)	(1,562)	607
Reduction of carrying value of oil and gas properties	6,408	9,891	
Net unrealized loss (gain) on oil and gas derivative financial instruments	121	(243)	26
Other noncash charges	222	410	150
Net decrease (increase) in working capital	149	(207)	(512)
Decrease (increase) in long-term other assets	(6)	(53)	(60)
Increase (decrease) in long-term other liabilities	(3)	48	(1)
Cash provided by operating activities continuing operations	4,232	8,448	5,308
Cash provided by operating activities discontinued operations	505	960	1,343
Net cash provided by operating activities	4,737	9,408	6,651
Cash flows from investing activities:			
Proceeds from sales of property and equipment	34	117	76
Capital expenditures	(4,879)	(8,843)	(5,710)
Proceeds from exchange of Chevron Corporation common stock		280	
Purchases of short-term investments		(50)	(934)
Sales of long-term and short-term investments	7	300	1,136
Other	(17)		
Cash used in investing activities continuing operations	(4,855)	(8,196)	(5,432)
Cash provided by (used in) investing activities discontinued operations	(499)	1,323	(282)
Net cash used in investing activities	(5,354)	(6,873)	(5,714)
Cash flows from financing activities:			
Proceeds from borrowings of long-term debt, net of issuance costs	1,187		
Credit facility repayments		(3,191)	(757)
Credit facility borrowings		1,741	2,207
Net commercial paper borrowings (repayments)	426	1	(804)
Debt repayments	(178)	(1,031)	(567)
Redemption of preferred stock		(150)	
Proceeds from stock option exercises	42	116	91

Repurchases of common stock		(665)	(326)
Dividends paid on common and preferred stock	(284)	(289)	(259)
Excess tax benefits related to share-based compensation	8	60	44
Net cash provided by (used in) financing activities	1,201	(3,408)	(371)
Effect of exchange rate changes on cash	43	(116)	51
Net increase (decrease) in cash and cash equivalents	627	(989)	617
Cash and cash equivalents at beginning of period (including cash related to assets held for sale)	384	1,373	756
Cash and cash equivalents at end of period (including cash related to assets held for sale)	$ 1,011	$ 384	$ 1,373

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 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 are concentrated in the following North American onshore geographic areas:

- the Mid-Continent area of the central and southern United States, principally in north and east Texas, as well as 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 onshore areas of the Gulf Coast, principally in south Texas and south Louisiana; and
- the provinces of Alberta, British Columbia and Saskatchewan in Canada.

Devon also has offshore operations located in the Gulf of Mexico and certain countries outside North America, including Azerbaijan, Brazil and China. In November 2009, Devon announced plans to strategically reposition itself as a high-growth, North American onshore exploration and production company. As part of this strategic repositioning, Devon plans to bring forward the value of its offshore assets by divesting them. In 2008 and 2007 prior to these plans, Devon sold its assets in Egypt and West Africa. These divestiture activities are described more fully in Note 18.

Devon also has marketing and midstream operations that perform various activities to support the oil and gas operations of Devon and unrelated third parties. Such activities include marketing gas, crude oil and NGLs, as well as constructing and operating pipelines, storage and treating facilities and natural gas processing plants.

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 the following:

estimates of proved reserves and related estimates of the present value of future net revenues;

the carrying value of oil and gas properties;

estimates of the fair value of reporting units and related assessment of goodwill for impairment;

asset retirement obligations;

income taxes;

derivative financial instruments;

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obligations related to employee pension and postretirement benefits; and

legal and environmental risks and exposures.

Derivative Financial Instruments

Devon is exposed to certain risks relating to its ongoing business operations. Devon s largest areas of risk exposure relate to commodity prices, interest rates and Canadian to U.S. dollar exchange rates. As discussed more fully below, Devon uses derivative instruments primarily to manage commodity price risk and interest rate risk. Besides these derivative instruments, Devon also had an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock. Devon ceased to have this option when the exchangeable debentures matured on August 15, 2008.

Devon periodically enters into derivative financial instruments with respect to a portion of its oil and gas production that hedge the future prices received. These instruments are used to manage the inherent uncertainty of future revenues due to oil and gas price volatility. Devon s derivative financial instruments include financial price swaps, basis swaps and costless price collars. Under the terms of the price swaps, Devon will receive a fixed price for its production and pay a variable market price to the contract counterparty. For the basis swaps, Devon receives a fixed differential between two regional gas index prices and pays a variable differential on the same two index prices to the contract counterparty. The price collars set a floor and ceiling price for the hedged production. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, Devon will cash-settle the difference with the counterparty to the collars.

Devon periodically enters into interest rate swaps to manage its exposure to interest rate volatility. Devon s interest rate swaps include contracts in which Devon receives a fixed rate and pays a variable rate on a total notional amount. Devon also has forward starting swaps. Under the terms of the forward starting swaps, Devon will net settle these contracts in September 2011 or sooner should Devon elect. The net settlement amount will be based upon Devon paying a fixed rate and receiving a floating rate that is based upon the three-month LIBOR. The difference between the fixed and floating rate will be applied to the notional amount for the 30-year period from September 30, 2011 to September 30, 2041.

All derivative financial instruments are recognized at their current fair value as either assets or liabilities in the balance sheet. Changes in the fair value of these 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. Cash settlements with counterparties to Devon s derivative financial instruments are also recorded in the statement of operations.

A derivative financial 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 a business combination or other transaction that 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. For derivative financial instruments held during the three-year period ended December 31, 2009, Devon chose not to meet the necessary criteria to qualify its derivative financial instruments for hedge accounting treatment.

By using derivative financial 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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

under the terms of the derivative contract. To mitigate this risk, the hedging instruments are placed with a number of counterparties whom 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. Additionally, Devon s derivative contracts generally require cash collateral to be posted if either its or the counterparty s credit rating falls below investment grade. The mark-to-market exposure threshold, above which collateral must be posted, decreases as the debt rating falls further below investment grade. Such thresholds generally range from zero to $50 million for the majority of our contracts. As of December 31, 2009, the credit ratings of all Devon s counterparties were investment grade.

Market risk is the change in the value of a derivative financial instrument that results from a change in commodity prices, interest rates or other relevant underlyings. The market risks associated with commodity price and interest rate contracts are 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 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 financial instruments for speculative trading purposes.

See Note 3 for the amounts included in Devon s accompanying consolidated balance sheets and consolidated statements of operations associated with its derivative financial instruments.

Fair Value Measurements

Certain of Devon s assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This is price is commonly referred to as the exit price .

Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. This hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 measurements are based on inputs other than quoted prices that are generally observable for the asset or liability. Common examples of Level 2 inputs include quoted prices for similar assets and liabilities in active markets or quoted prices for identical assets and liabilities in markets not considered to be active. Level 3 measurements have the lowest priority and are based upon inputs that are not observable from objective sources. The most common Level 3 fair value measurement is an internally developed cash flow model. Devon uses appropriate valuation techniques based on the available inputs to measure the fair values of its assets and liabilities. When available, Devon measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.

Discontinued Operations

As previously discussed, Devon is in the process of divesting its offshore assets in the Gulf of Mexico and certain International locations outside North America and previously sold its assets in Africa in 2008 and 2007. As a result of these divestitures and planned divestitures, all amounts related to Devon s International operations are classified as discontinued operations. The Gulf of Mexico properties being divested do not qualify as discontinued operations under accounting rules. As such, amounts included in the accompanying consolidated financial statements and these notes that pertain to continuing operations include amounts related to Devon s offshore Gulf of Mexico operations.

The captions assets held for sale and liabilities associated with assets held for sale in the accompanying consolidated balance sheets present the assets and liabilities associated with Devon s discontinued operations. Devon measures its assets held for sale at the lower of its carrying amount or estimated fair value less costs to

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

sell. Additionally, Devon does not recognize depreciation, depletion and amortization on its long-lived assets held for sale.

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 that are not related to production, general corporate overhead or similar activities, are also capitalized. Interest costs incurred and attributable to unproved oil and gas properties under current evaluation and major development projects of oil and gas properties are also capitalized. 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, 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.

Future net revenues are calculated using prices that represent the average of the first-day-of-the-month price for the 12-month period prior to the end of the period. Costs included in future net revenues are determined in a similar manner. Prior to December 31, 2009, prices and costs used to calculate future net revenues were those as of the end of the appropriate quarterly period. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including derivative contracts in place that qualify for hedge accounting treatment. None of Devon s derivative contracts held during the three-year period ended December 31, 2009 qualified for hedge accounting treatment.

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 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.

Costs associated with unproved properties are excluded from the depletion calculation 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 into the depletion calculation 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 unit-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.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Devon recognizes liabilities for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and midstream pipelines and 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.

Investments

Devon reports its investments and other marketable securities at fair value, except for debt securities in which management has the ability and intent to hold until maturity.

Devon s primary investments consist of auction rate securities that totaled $115 million and $122 million at December 31, 2009 and 2008, respectively. These securities are rated AAA the highest rating by one or more rating agencies and are collateralized by student loans that are substantially guaranteed by the United States government. Although Devon s auction rate securities generally have contractual maturities of more than 20 years, the underlying interest rates on such securities are scheduled to reset every seven to 28 days. Therefore, these auction rate securities were generally priced and subsequently traded as short-term investments because of the interest rate reset feature.

Since February 8, 2008, Devon has experienced difficulty selling its securities due to the failure of the auction mechanism, which provided liquidity to these securities. An auction failure means that the parties wishing to sell securities could not do so. The securities for which auctions have failed will continue to accrue interest and be auctioned every seven to 28 days until the auction succeeds, the issuer calls the securities or the securities mature.

From February 2008, when auctions began failing, to December 31, 2009, issuers have redeemed $37 million of Devon s auction rate securities holdings at par. However, based on continued auction failures and the current market for Devon s auction rate securities, Devon has classified its auction rate securities as long-term investments as of December 31, 2009. These securities are included in other long-term assets in the accompanying consolidated balance sheet. Devon has the ability to hold the securities until maturity. At this time, Devon does not believe the values of its long-term securities are impaired.

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 2009, 2008 and 2007. 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, 2009 and 2008. The increase in goodwill from 2008 to 2009 is due to changes in the exchange rate between the U.S. dollar and the Canadian dollar.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	December 31, 2009	December 31, 2008
	(In millions)	
United States	$ 3,046	$ 3,046
Canada	2,884	2,465
Total (continuing operations)	$ 5,930	$ 5,511
International (assets held for sale)	$ 68	$ 68

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, 2006	$ 1,219
December 31, 2007	$ 2,566
December 31, 2008	$ 685
December 31, 2009	$ 1,616

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. Liabilities for environmental remediation or restoration claims are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with Devon s accounting policy for property and equipment. Reference is made to Note 10 for a discussion of amounts recorded for these liabilities.

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 collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar 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 in the accompanying consolidated statements 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 underproduced owner to recoup its entitled share through production. The liability is priced based on current market prices. No receivables are recorded for those wells where Devon has taken less than its share of production unless all revenue recognition criteria are met. 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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 collectability of the revenue is probable. Revenues and expenses attributable to gas and NGL purchase, transportation and processing contracts are reported on a gross basis when Devon takes title to the products and has risks and rewards of ownership.

Major Purchasers

During 2009, 2008 and 2007, no purchaser accounted for more than 10% of Devon s revenues from continuing operations.

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.

Share Based Compensation

Devon grants stock options, restricted stock awards and other types of share-based awards to members of its Board of Directors and selected employees. All such awards are measured at fair value on the date of grant and are recognized as a component of general and administrative expenses or restructuring costs in the accompanying statements of operations over the applicable requisite service periods. Generally, Devon uses new shares to grant share-based awards and to issue shares upon stock option exercises.

Income Taxes

Devon is subject to current income taxes assessed by the federal and various state jurisdictions in the United States and by other foreign jurisdictions. In addition, Devon accounts for deferred income taxes related to these jurisdictions using the asset and liability method. Under this method, 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. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards 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.

Devon recognizes the financial statement effects of tax positions when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. Recognized tax positions are initially and subsequently measured as the largest amount of tax benefit that is more likely than not of being realized upon ultimate settlement with a taxing authority. Liabilities for unrecognized tax benefits related to such tax positions are included in other long-term liabilities unless the tax position is expected to be settled within the upcoming year, in which case the liabilities are included in accrued expenses and other current liabilities. Interest and penalties related to unrecognized tax benefits are included in income tax expense. Additional information regarding Devon s unrecognized tax benefits, including changes in such amounts during 2009 and 2008, is provided in Note 17.

Pursuant to the planned divestitures of its International assets located outside North America, Devon expects to repatriate the earnings from the foreign subsidiaries that own the assets. As a result, Devon has recognized U.S. deferred income taxes on its foreign earnings as of December 31, 2009.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Net (Loss) Earnings Per Common Share

Devon s basic earnings per share amounts have been computed based on the average number of shares of common stock outstanding for the period. Basic earnings per share includes the effect of participating securities, which primarily consist of Devon s outstanding restricted stock awards. Diluted earnings per share is calculated using the treasury stock method to reflect the potential dilution that could occur if Devon s dilutive outstanding stock options were exercised.

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.

2. Accounts Receivable

The components of accounts receivable include the following:

	December 31, 2009	December 31, 2008
	(In millions)	
Oil, gas and NGL revenues	$ 752	$ 711
Joint interest billings	151	241
Marketing and midstream revenues	188	153
Production tax credits	110	170
Other	19	30
Gross accounts receivable	1,220	1,305
Allowance for doubtful accounts	(12)	(5)
Net accounts receivable	$ 1,208	$ 1,300

3. Derivative Financial Instruments

As discussed in Note 1, Devon periodically enters into commodity and interest rate derivative financial instruments. Also, during the first eight months of 2008 and all of 2007, Devon held an embedded option derivative related to the fair value of its debentures exchangeable into shares of Chevron common stock.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the fair values of derivative assets and liabilities included in the accompanying consolidated balance sheets. None of Devon s derivative instruments included in the table have been designated as hedging instruments.

	Balance Sheet Caption	Asset Derivatives	Liability Derivatives
		(In millions)	
December 31, 2009:			
Gas price swaps	Derivative financial instruments, current	$ 169	$
Gas basis swaps	Derivative financial instruments, current	3	
Oil price collars	Other current liabilities		38
Interest rate swaps	Derivative financial instruments, current	39	
Interest rate swaps	Other long-term assets	131	
Total derivatives		$ 342	$ 38
December 31, 2008:			
Gas price collars	Derivative financial instruments, current	$ 255	$
Interest rate swaps	Derivative financial instruments, current	27	
Interest rate swaps	Other long-term assets	77	
Total derivatives		$ 359	$

The following table presents the cash settlements and unrealized gains and losses on fair value changes included in the accompanying statements of operations associated with these derivative financial instruments. None of Devon s derivative instruments included in the table have been designated as hedging instruments.

	Statement of Operations Caption	2009	2008	2007
			(In millions)	
Cash settlements:				
Gas price collars	Net gain (loss) on oil and gas derivative financial instruments	$ 450	$ (221)	$ 2
Gas price swaps	Net gain (loss) on oil and gas derivative financial instruments	55	(203)	38
Oil price collars	Net gain (loss) on oil and gas derivative financial instruments		27	
Interest rate swaps	Change in fair value of other financial instruments	40	1	
Total cash settlements		545	(396)	40

Unrealized (losses) gains:				
Gas price collars	Net gain (loss) on oil and gas derivative financial instruments	(255)	255	(4)
Gas price swaps	Net gain (loss) on oil and gas derivative financial instruments	169	(12)	(22)
Gas basis swaps	Net gain (loss) on oil and gas derivative financial instruments	3		
Oil price collars	Net gain (loss) on oil and gas derivative financial instruments	(38)		
Interest rate swaps	Change in fair value of other financial instruments	66	104	1
Embedded option	Change in fair value of other financial instruments		109	(248)
Total unrealized (losses) gains		(55)	456	(273)
Net gain (loss) recognized on statement of operations		$ 490	$ 60	$ (233)

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Other Current Assets

The components of other current assets include the following:

	December 31, 2009	December 31, 2008
	(In millions)	
Inventories	$ 182	$ 142
Prepaid assets	33	36
Income taxes receivable	53	333
Other	2	4
Other current assets	$ 270	$ 515

5. Property and Equipment

Property and equipment consists of the following:

	December 31, 2009	December 31, 2008
	(In millions)	
Oil and gas properties:		
Subject to amortization	$ 52,352	$ 45,678
Not subject to amortization	4,078	4,248
Total	56,430	49,926
Accumulated depreciation, depletion and amortization	(40,312)	(30,260)
Net oil and gas properties	16,118	19,666
Other property and equipment	4,045	3,465
Accumulated depreciation and amortization	(1,396)	(1,100)
Net other property and equipment	2,649	2,365
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 18,767	$ 22,031

In the first quarter of 2009 and the fourth quarter of 2008, Devon reduced the carrying values of its oil and gas properties due to full cost ceiling limitations. These reductions are discussed in Note 15.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following is a summary of Devon s oil and gas properties not subject to amortization as of December 31, 2009. The $4.1 billion total includes $2.1 billion related to Devon s U.S. Offshore assets that are expected to be sold by the end of 2010. Evaluation of most of the remaining $2.0 billion of properties, and therefore the inclusion of their costs in amortized capital costs, is expected to be completed within three to seven years.

	Costs Incurred In				
	2009	2008	2007	Prior to 2007	Total
	(In millions)				
Acquisition costs	$ 129	$ 1,567	$ 126	$ 780	$ 2,602
Exploration costs	223	303	56	174	756
Development costs	326	169	34	22	551
Capitalized interest	74	54	37	4	169
Total oil and gas properties not subject to amortization	$ 752	$ 2,093	$ 253	$ 980	$ 4,078

6. Debt and Related Expenses

A summary of Devon s debt is as follows:

	December 31,	
	2009	2008
	(In millions)	
Commercial paper	$ 1,432	$ 1,005
Other debentures and notes:		
10.125% retired on November 15, 2009		177
6.875% due September 30, 2011	1,750	1,750
7.25% due October 1, 2011	350	350
5.625% due January 15, 2014	500	
8.25% due July 1, 2018	125	125
6.30% due January 15, 2019	700	
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	10	10
Net premium on other debentures and notes	12	24
	7,279	5,841
Less amount classified as short-term debt	1,432	180

Long-term debt	$ 5,847	$ 5,661

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Debt maturities as of December 31, 2009, excluding premiums and discounts, are as follows (in millions):

2010	$ 1,432
2011	2,100
2012	10
2013	
2014	500
2015 and thereafter	3,225
Total	$ 7,267

Credit Lines

Devon has a $2.65 billion syndicated, unsecured revolving line of credit (the Senior Credit Facility). The maturity date for $2.15 billion of the Senior Credit Facility is April 7, 2013. The maturity date for the remaining $0.5 billion is April 7, 2012. All amounts outstanding will be due and payable on the respective maturity dates 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. The Senior Credit Facility includes a revolving Canadian subfacility in a maximum amount of U.S. $500 million.

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. However, Devon may elect to borrow at the prime rate. The Senior Credit Facility currently provides for an annual facility fee of $1.9 million that is payable quarterly in arrears. As of December 31, 2009, there were no borrowings under the Senior Credit Facility.

Following the maturity of an unused $700 million short-term facility on November 3, 2009, Devon established a new $700 million 364-day, syndicated, unsecured revolving senior credit facility (the Short-Term Facility). The Short-Term Facility provides Devon with incremental liquidity for near-term capital expenditures.

The Short-Term Facility matures on November 2, 2010. On the maturity date, all amounts outstanding will be due and payable at that time. Amounts borrowed under the Short-Term Facility bear interest at various fixed rate options for periods of up to 12 months. Such rates are generally based on LIBOR or the prime rate. The Short-Term Facility provides for an annual facility fee of approximately $1.75 million that is payable quarterly in arrears. As of December 31, 2009, there were no borrowings under the Short-Term Facility.

The Senior Credit Facility and Short-Term Facility contain only one material financial covenant. This covenant requires Devon s 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 the consolidated financial statements. Also, total capitalization is adjusted to add back noncash financial writedowns such as full cost ceiling impairments or goodwill impairments. As of December 31, 2009, Devon was in compliance with this covenant. Devon s debt-to-capitalization ratio at December 31, 2009, as calculated pursuant to the terms of the agreement, was 20.5%.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following schedule summarizes the capacity of Devon s credit facilities by maturity date, as well as its available capacity as of December 31, 2009 (in millions).

Senior Credit Facility:	
April 7, 2012 maturity	$ 500
April 7, 2013 maturity	2,150
Total Senior Credit Facility	2,650
Short-Term Facility November 2, 2010 maturity	700
Total credit facilities	3,350
Less:	
Outstanding credit facility borrowings	
Outstanding commercial paper borrowings	1,432
Outstanding letters of credit	87
Total available capacity	$ 1,831

Commercial Paper

Devon also has access to short-term credit under its commercial paper program. Total borrowings under the commercial paper program may not exceed $2.85 billion. Also, any borrowings under the commercial paper program reduce available capacity under the Senior Credit Facility or the Short-Term Facility on a dollar-for-dollar basis. Commercial paper debt generally has a maturity of between one 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, 2009, Devon had $1.4 billion of commercial paper debt outstanding at an average rate of 0.29%. The average borrowing rate for Devon s $1.0 billion of commercial paper debt outstanding at December 31, 2008 was 3.00%.

Other Debentures and Notes

Following are descriptions of the various other debentures and notes outstanding at December 31, 2009, as listed in the table presented at the beginning of this note.

Ocean Debt

As a result of the merger with Ocean Energy, Inc., which closed April 25, 2003, Devon assumed $1.8 billion of debt. The table below summarizes the debt assumed that 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 resulting from fair values exceeding face values 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
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%

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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), a wholly-owned finance subsidiary, 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 acquisition of Anderson Exploration.

5.625% Notes due January 15, 2014 and 6.30% Notes due January 15, 2019

On January 9, 2009, Devon sold these notes, which are unsecured and unsubordinated obligations of Devon. The net proceeds from issuance of this debt were used primarily to repay Devon s outstanding commercial paper as of December 31, 2008.

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 2007 and 2009.

	Year Ended December 31,		
	2009	2008	2007
	(In millions)		
Interest based on debt outstanding	$ 437	$ 426	$ 508
Capitalized interest	(94)	(111)	(102)
Other	6	14	24
Total interest expense	$ 349	$ 329	$ 430

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Asset Retirement Obligations

Following is a reconciliation of the asset retirement obligations for the years ended December 31, 2009 and 2008.

	Year Ended December 31, 2009	2008
	(In millions)	
Asset retirement obligations as of beginning of year	$ 1,387	$ 1,245
Liabilities incurred	56	59
Liabilities settled	(123)	(86)
Revision of estimated obligation	33	225
Liabilities assumed by others	(30)	
Accretion expense on discounted obligation	91	80
Foreign currency translation adjustment	99	(136)
Asset retirement obligations as of end of year	1,513	1,387
Less current portion	95	138
Asset retirement obligations, long-term	$ 1,418	$ 1,249

During 2009 and 2008, Devon recognized revisions to its asset retirement obligations totaling $33 million and $225 million, respectively. The primary factors causing the 2009 fair value increase were an overall increase in abandonment cost estimates, partially offset by an increase in the discount rate used to calculate the present value of the obligations. The primary factors causing the 2008 fair value increase were an overall increase in abandonment cost estimates and a decrease in the discount rate used to present value the obligations. In addition, higher abandonment cost estimates related to certain offshore platforms that were destroyed by Hurricane Ike resulted in an $82 million increase in 2008. See additional discussion regarding this revision in Note 10 Hurricane Contingencies.

8. 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 employees years of service and compensation and are funded from assets held in the plans trusts.

Devon s funding policy regarding the Qualified Plans is to contribute the amount of funds necessary for the Qualified Plans assets to approximately equal the present value of benefits earned by the participants, as calculated in accordance with the provisions of the Pension Protection Act. As of December 31, 2009 and 2008, the fair values of the Qualified Plans assets were $532 million and $430 million, respectively. The assets were $164 million less and

$209 million less, respectively, than the related accumulated benefit obligation. The 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 employees 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 $39 million and $50 million at December 31, 2009 and 2008, respectively, and is included in noncurrent other assets in the consolidated

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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) that 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 Devon s future cost-sharing intentions. Devon s funding policy for the Postretirement Plans is to fund the benefits as they become payable with available cash and cash equivalents.

Benefit Obligations and Funded Status

The following table presents the status of Devon s pension and other postretirement benefit plans for 2009 and 2008. 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, 2009 and 2008 was $873 million and $795 million, respectively. Devon s benefit obligations and plan assets are measured each year as of December 31.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 931	$ 849	$ 56	$ 71
Service cost	43	41	1	1
Interest cost	58	54	3	4
Actuarial loss (gain)	4	17	7	(15)
Curtailment (gain) loss	(26)		1	
Plan amendments		9		
Foreign exchange rate changes	5	(6)		
Participant contributions			2	2
Benefits paid	(35)	(33)	(6)	(7)
Benefit obligation at end of year	980	931	64	56
Change in plan assets:				
Fair value of plan assets at beginning of year	430	619		
Actual return on plan assets	80	(178)		
Employer contributions	55	25	4	5
Participant contributions			2	2
Benefits paid	(35)	(33)	(6)	(7)
Foreign exchange rate changes	2	(3)		
Fair value of plan assets at end of year	532	430		
Funded status at end of year	$ (448)	$ (501)	$ (64)	$ (56)
Amounts recognized in balance sheet:				
Noncurrent assets	$ 2	$ 2	$	$
Current liabilities	(8)	(10)	(5)	(5)
Noncurrent liabilities	(442)	(493)	(59)	(51)
Net amount	$ (448)	$ (501)	$ (64)	$ (56)
Amounts recognized in accumulated other comprehensive income:				
Net actuarial loss (gain)	$ 334	$ 440	$ (6)	$ (13)
Prior service cost	20	28	11	13
Total	$ 354	$ 468	$ 5	$

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 $9 million for both 2009 and 2008, which were transferred from the trusts established for the Supplemental Plans.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Certain of Devon s pension plans have a projected benefit obligation and accumulated benefit obligation in excess of plan assets at December 31, 2009 and 2008 as presented in the table below.

	December 31, 2009	December 31, 2008
	(In millions)	
Projected benefit obligation	$ 967	$ 921
Accumulated benefit obligation	$ 860	$ 784
Fair value of plan assets	$ 517	$ 417

The plan assets included in the above table exclude the Supplemental Plan trusts, which had a total value of $39 million and $50 million at December 31, 2009 and 2008, respectively.

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 2009, 2008 and 2007.

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
	(In millions)					
Net periodic benefit cost:						
Service cost	$ 43	$ 41	$ 30	$ 1	$ 1	$ 1
Interest cost	58	54	46	3	4	3
Expected return on plan assets	(35)	(50)	(49)			
Curtailment and settlement expense	5		1	1		
Plan amendment						1
Recognition of net actuarial loss (gain)	45	14	12	(1)		1
Recognition of prior service cost	3	2	1	2	2	
Total net periodic benefit cost	119	61	41	6	7	6
Other comprehensive income						
Actuarial (gain) loss arising in current year	(66)	245	54	7	(15)	(3)
Prior service cost arising in current year		9	17			22
Recognition of net actuarial (loss) gain in net periodic benefit cost	(45)	(14)	(12)	1		(1)
Recognition of prior service cost, including curtailment, in net periodic benefit cost	(8)	(2)	(1)	(2)	(2)	
Curtailment of pension benefits			(16)			

Change in additional minimum pension liability						
Total other comprehensive income (loss)	(119)	238	42	6	(17)	18
Total recognized	$	$ 299	$ 83	$ 12	$ (10)	$ 24

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2010.

	Pension Benefits	Other Postretirement Benefits
	(In millions)	
Net actuarial loss	$ 27	$
Prior service cost	3	1
Total	$ 30	$ 1

Assumptions

The following table presents the weighted average actuarial assumptions that were used to determine benefit obligations and net periodic benefit costs for 2009, 2008 and 2007.

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
Assumptions to determine benefit obligations:						
Discount rate	6.00%	6.00%	6.22%	5.70%	6.00%	6.00%
Rate of compensation increase	6.95%	7.00%	7.00%	N/A	N/A	N/A
Assumptions to determine net periodic benefit cost:						
Discount rate	6.00%	6.18%	5.96%	6.00%	6.00%	5.75%
Expected return on plan assets	7.18%	8.40%	8.40%	N/A	N/A	N/A
Rate of compensation increase	6.95%	7.00%	7.00%	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 future cash flows related to the plans. 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 2009 benefit obligation for the pension plans, the 6.95% compensation increase in the table above represents the assumed increase through 2011. The rate was assumed to decrease to 5% in the year 2012 and remain at that level thereafter.

Expected return on plan assets 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. See plan assets discussion below for more information on Devon s target allocations.

Other assumptions For measurement of the 2009 benefit obligation for the other postretirement medical plans, an 8.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010. The rate was assumed to decrease annually to an ultimate rate of 5% in the year 2029 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

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

effects on the December 31, 2009 other postretirement benefits obligation and the 2010 service and interest cost components of net periodic benefit cost.

	One Percent Increase	One Percent Decrease
	(In millions)	
Effect on benefit obligation	$ 5	$ (4)
Effect on service and interest costs	$	$

Pension Plan Assets

Devon s overall investment objective for its pension plans assets is to achieve long-term growth of invested capital and income to ensure benefit payments 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.

The vast majority of Devon s plan assets are invested in diversified asset types to generate long-term growth and income. The remaining plan assets, generally less than 5%, are invested in assets that can be used for near-term benefit payments. Derivatives or other speculative investments considered high risk are generally prohibited.

At the end of 2009, Devon s target allocations for plan assets are 47.5% for equity securities, 40% for fixed-income securities and 12.5% for other investment types. At the end of 2008, Devon s target allocation was 60% for equity securities and 40% for fixed income securities. The fair values of Devon s pension assets at December 31, 2009 and 2008, are presented by asset class in the following tables.

		As of December 31, 2009			
			Fair Value Measurements Using:		
	Actual Allocation	Total	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(In millions)			
Equity securities:					
United States large cap	18.8%	$ 100	$	$ 100	$
United States small cap	15.2%	81	81		
International large cap	15.2%	81	44	37	
Total equity securities	49.2%	262	125	137	

Fixed-income securities:					
Corporate bonds	25.1%	133	133		
United States Treasury obligations	9.8%	52	52		
Other bonds	3.9%	21	21		
Total fixed-income securities	38.8%	206	206		
Other securities:					
Short-term investment funds	2.4%	13		13	
Hedge funds	9.6%	51			51
Total other securities	12.0%	64		13	51
Total investments	100.0%	$ 532	$ 331	$ 150	$ 51

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			As of December 31, 2008 Fair Value Measurements Using:		
	Actual Allocation	Total	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(In millions)		
Equity securities:					
United States large cap	25.8%	$ 111	$	$ 111	$
United States small cap	14.9%	64	64		
International large cap	14.0%	60	34	26	
Total equity securities	54.7%	235	98	137	
Fixed-income securities:					
Corporate bonds	29.1%	125	125		
United States Treasury obligations	8.8%	38	38		
Other bonds	3.0%	13	13		
Total fixed-income securities	40.9%	176	176		
Other securities Short-term investment funds	4.4%	19		19	
Total investments	100.0%	$ 430	$ 274	$ 156	$

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the tables above.

Equity securities Devon s equity securities consist of investments in United States large and small capitalization companies and international large capitalization companies. These equity securities are actively traded securities that can be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices.

Devon s equity securities also include commingled funds that invest in large capitalization companies. These equity securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by the investment managers.

Fixed-income securities Devon s fixed-income securities consist of bonds issued by investment-grade companies from diverse industries, United States Treasury obligations and asset-backed securities. Devon s fixed-income securities are actively traded securities that can be redeemed upon demand. The fair values of these Level 1 securities are based upon quoted market prices.

Other securities Devon s other securities include commingled, short-term investment funds. These securities can be redeemed on demand but are not actively traded. The fair values of these Level 2 securities are based upon the net asset values provided by investment managers.

Devon s other securities also include a hedge fund of funds that invests both long and short using a variety of investment strategies. Management of the hedge fund has the ability to shift investments from value to growth strategies, from small to large capitalization stocks, and from a net long position to a net short position. Devon s hedge fund is not actively traded and Devon is subject to redemption restrictions with regards to this investment. The fair value of this Level 3 investment represents the fair value as determined by the hedge fund manager.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The change in Devon s Level 3 plan assets between 2008 and 2009 related entirely to purchases made in 2009.

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 s 2010 contributions	$ 34	$ 5
Benefit payments:		
2010	$ 39	$ 5
2011	$ 41	$ 5
2012	$ 45	$ 6
2013	$ 49	$ 6
2014	$ 53	$ 6
2015 to 2019	$ 338	$ 29

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 2010, $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 s 401(k) Plan covers all its employees in the United States. 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.

In 2007, Devon adopted an enhanced defined contribution structure related to its 401(k) Plan effective January 1, 2008. Participants who elected to participate in this enhanced defined contribution structure, as well as all employees hired on or after October 1, 2007, continue to receive a discretionary match of a percentage of their contributions to the 401(k) Plan. These participants also receive additional, nondiscretionary contributions by Devon calculated as a percentage of annual compensation. The percentage will vary based on the employees years of service.

Devon has defined contribution pension plans for its Canadian employees. Devon makes a contribution to each employee that 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents Devon s expense related to these defined contribution plans during 2009, 2008 and 2007.

	Year Ended December 31, 2009	2008	2007
	(In millions)		
401(k) plan	$ 20	$ 21	$ 18
Enhanced contribution plan	14	12	
Canadian pension and savings plans	15	16	14
Total expense	$ 49	$ 49	$ 32

9. Stockholders Equity

The authorized capital stock of Devon consists of 1 billion 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.

Devon s Board of Directors has designated 2.9 million shares of the preferred stock as Series A Junior Participating Preferred Stock (the Series A Junior Preferred Stock). At December 31, 2009, 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.

Preferred Stock Redemption

On June 20, 2008, Devon redeemed all 1.5 million outstanding shares of its 6.49% Series A cumulative preferred stock. Each share of preferred stock was redeemed for cash at a redemption price of $100 per share, plus accrued and unpaid dividends up to the redemption date.

Stock Repurchases

Devon s Board of Directors previously approved an ongoing, annual stock repurchase program to minimize dilution resulting from restricted stock issued to, and options exercised by, employees. Also, Devon s Board of Directors approved a program in 2007 to repurchase up to 50 million shares. This program was created as a potential use of the proceeds received from Devon s West African property divestitures. Both of these plans expired on December 31, 2009, and no new plans have been authorized. Devon s Board of Directors also approved a separate 50 million share repurchase program in August 2005, which expired on December 31, 2007.

During 2007 and 2008, Devon repurchased 10.6 million shares at a total cost of $1.0 billion, or an average of $93.76 per share, under its repurchase programs. No shares were repurchased in 2009. The

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

following table summarizes Devon s repurchases under approved plans during 2008 and 2007 (amounts and shares in millions).

	2008			2007		
Repurchase Program	**Amount**	**Shares**	**Per Share**	**Amount**	**Shares**	**Per Share**
Annual program	$ 178	2.0	$ 87.83	$		$
2007 program	487	4.5	$ 109.25	326	4.1	$ 79.80
Totals	$ 665	6.5	$ 102.56	$ 326	4.1	$ 79.80

Dividends

Devon paid common stock dividends of $284 million (or $0.64 per share), $284 million (or $0.64 per share) and $249 million (or $0.56 per share) in 2009, 2008 and 2007 respectively. Devon paid dividends of $5 million in 2008 and $10 million in 2007 to preferred stockholders. The decrease in preferred stock dividend in 2008 is due to the redemption of the preferred stock in the second quarter of 2008.

10. 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 and similar state statutes. In response to liabilities associated with these activities, loss accruals primarily consist of estimated uninsured costs associated with remediation. Devon s monetary exposure for environmental matters is not expected to be material.

Royalty Matters

Numerous natural 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 NGLs produced and sold from federal and Indian owned or controlled lands. Devon does not currently believe that it is subject to material exposure with respect to such royalty matters.

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 gas exceeded the thresholds for a given year, royalty relief would not be granted for that year.

In October 2007, a federal district court ruled in favor of a plaintiff who had challenged the legality of including price thresholds in deep water leases. Additionally, in January 2009 a federal appellate court upheld this district court ruling. This judgment was later appealed to the United States Supreme Court, which, in

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

October 2009, declined to review the appellate court s ruling. The Supreme Court s decision ended the MMS s judicial course to enforce the price thresholds.

Prior to September 30, 2009, Devon had $84 million accrued for potential royalties on various deep water leases. Based upon the Supreme Court s decision, Devon reduced to zero the $84 million loss contingency accrual in the third quarter of 2009. The $84 million expense reduction is included in other income in the accompanying 2009 consolidated statement of operations.

Hurricane Contingencies

Prior to September 1, 2006, Devon maintained a comprehensive insurance program that included coverage for physical damage to its offshore facilities caused by hurricanes. This program also included substantial business interruption coverage, which entitled Devon to be reimbursed for the portion of production suspended longer than forty-five days, subject to upper limits to oil and gas prices. Also, the terms of the historical insurance included a standard, per-event deductible of $1 million for offshore losses as well as a $15 million aggregate annual deductible.

Devon suffered insured damages in the third quarter of 2005 related to hurricanes that struck the Gulf of Mexico. During 2006 and 2007, Devon received $480 million as a full settlement of the amount due from its primary insurers and certain of its secondary insurers. During the fourth quarter of 2008, Devon received $106 million as full settlement of the amount due from its remaining secondary insurers. Devon s claims under its then existing insurance arrangements included both physical damages and business interruption claims. Devon used $424 million of these proceeds as reimbursement of repair costs and deductible amounts, resulting in excess recoveries. The $162 million of excess recoveries was recorded as other income in the accompanying consolidated statement of operations for 2008.

The policy underlying the insurance program terms described above expired on August 31, 2006. Due to significant changes in the insurance marketplace, Devon no longer has coverage for damage that may be caused by named windstorms in the Gulf of Mexico. As a result, Devon s current insurance program includes coverage for physical damage and business interruption but does not have such coverage for damages or business interruption caused from named windstorms in the Gulf of Mexico.

During the third quarter of 2008, Hurricanes Ike and Gustav damaged certain of Devon s oil and gas facilities and transportation systems in the Gulf of Mexico. These damages relate to both production operations that have been repaired and restored and production operations that will not be restored. These damages are uninsured losses because they resulted from named windstorms in the Gulf of Mexico.

For the damaged facilities and transportation systems which have been repaired or restored, Devon recognized a loss of $31 million in 2008. This loss is included in lease operating expenses in the accompanying consolidated statement of operations. The facilities for which Devon did not restore production operations consisted of certain platforms that were completely destroyed. Devon began performing asset retirement activities associated with the destroyed platforms and related wells in 2008. The time and effort required to complete such activities is expected to be significant due to the hazardous conditions created by the hurricanes. As a result, the estimated costs to complete the asset retirement activities were $82 million higher than Devon s previously estimated asset retirement obligations related to the destroyed platforms and related wells. Therefore, in 2008, Devon increased its asset retirement obligations by $82 million with a corresponding increase to oil and gas property and equipment in the accompanying consolidated balance sheet.

Other Matters

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

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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 $3.2 billion total of Drilling and Facility Obligations in the table below is $1.4 billion that 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 $1.4 billion represents the gross commitment under these contracts. Devon s ultimate payment for these commitments will be reduced by any amounts billed to its partners until Devon sells the associated offshore properties. Payments for these commitments, net of amounts billed to partners, will be capitalized as a component of oil and gas properties.

Additionally, Devon s commitment under these contracts may be further reduced if the buyers of its offshore assets assume all or a portion of the obligations. If the buyers do not assume these obligations, Devon will attempt to sublease the rigs to reduce its commitment. However, if the buyers do not assume the obligations and Devon is not able to sublease the rigs, Devon would be contractually committed to the amounts related to the remaining lease periods.

Devon has certain firm transportation agreements that 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 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 $56 million, $44 million and $42 million in 2009, 2008 and 2007, 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 the Nansen operating lease was $12 million in 2009, 2008 and 2007. 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 2018. Devon is also leasing an FPSO that is being used in the Polvo project offshore Brazil. This lease expires in 2014. Devon has also leased an FPSO that will be used when production from its Cascade development in the Gulf of Mexico begins in 2010. This lease expires in 2015. Total rental expense included in lease operating expenses for these FPSO s was $36 million, $25 million and $17 million in 2009, 2008 and 2007, respectively. Devon expects the eventual buyers of these offshore assets will assume the FPSO leases. However, the amounts in the schedule below reflect its full commitments under the leases.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2009. The schedule includes separate amounts for Devon s continuing and discontinued operations.

Year Ending December 31,	Drilling and Facility Obligations	Firm Transportation Agreements	Office and Equipment Leases	Spar Leases	FPSO Leases
			(In millions)		
Continuing operations:					
2010	$ 992	$ 298	$ 57	$ 11	$ 58
2011	516	267	54	11	37
2012	302	241	40	22	38
2013	257	217	34	13	38
2014	97	202	15	27	38
Thereafter	1	714	147	78	16
Total	2,165	1,939	347	162	225
Discontinued operations:					
2010	622		15		37
2011	182				37
2012	170				37
2013	110				37
2014					23
Thereafter					29
Total	1,084		15		200
Total operations	$ 3,249	$ 1,939	$ 362	$ 162	$ 425

11. Fair Value Measurements

Certain of Devon s assets and liabilities are reported at fair value in the accompanying balance sheets. Such assets and liabilities include amounts for both financial and nonfinancial instruments. The following tables provide fair value measurement information for such assets and liabilities as of December 31, 2009 and 2008.

The carrying values of cash and cash equivalents, 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, 2009 and 2008. These assets and liabilities are not presented in the following tables.

Information regarding the fair values of Devon s pension plan assets is provided in Note 8.

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			As of December 31, 2009		
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(In millions)		
Financial assets (liabilities):					
Gas price swaps	$ 169	$ 169	$	$ 169	$
Gas basis swaps	$ 3	$ 3	$	$ 3	$
Oil price collars	$ (38)	$ (38)	$	$ (38)	$
Interest rate swaps	$ 170	$ 170	$	$ 170	$
Debt	$ (7,279)	$ (8,214)	$ (1,432)	$ (6,782)	$
Long-term investments	$ 115	$ 115	$	$	$ 115
Asset retirement obligations(1)	$ (1,622)	$ (1,622)	$	$	$ (1,622)

			As of December 31, 2008		
			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			(In millions)		
Financial assets (liabilities):					
Gas price collars	$ 255	$ 255	$	$ 255	$
Interest rate swaps	$ 104	$ 104	$	$ 104	$
Debt	$ (5,841)	$ (6,106)	$ (1,005)	$ (5,101)	$
Long-term investments	$ 122	$ 122	$	$	$ 122
Asset retirement obligations(1)	$ (1,485)	$ (1,485)	$	$	$ (1,485)

(1) Includes $109 million and $98 million of asset retirement obligations related to Devon s discontinued operations at December 31, 2009 and 2008, respectively.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the tables above.

Level 1 Fair Value Measurements

Debt The fair value of Devon s variable-rate commercial paper borrowings is the carrying value.

Level 2 Fair Value Measurements

Oil and gas price swaps, basis swaps and collars The fair values of the oil and gas price collars, gas swaps and gas basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves, quotes obtained from brokers for contracts with similar terms or quotes obtained from counterparties to the agreements. The most significant input to the cash flow calculations is Devon s estimate of future commodity prices. Devon bases its estimate of future prices upon published forward commodity price curves such as the Inside FERC Henry Hub forward curve for gas instruments and the NYMEX West Texas Intermediate forward curve for oil instruments. Another key input to the cash flow calculations is Devon s estimate of volatility for these forward curves, which is based primarily upon implied

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volatility. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted primarily using LIBOR and money market futures rates. These pricing and discounting inputs are sensitive to the period of the contract, as well as changes in forward prices and regional price differentials.

Interest rate swaps The fair values of the interest rate swaps are estimated using internal discounted cash flow calculations based upon forward interest-rate yield curves or quotes obtained from counterparties to the agreements. The most significant input to Devon s cash flow calculations is its estimate of future interest rate yields. Devon bases its estimate of future yields upon its own internal model that utilizes forward curves such as the LIBOR or the Federal Funds Rate provided by third parties. The resulting estimated future cash inflows or outflows over the lives of the contracts are discounted primarily using LIBOR and money market futures rates. These yield and discounting inputs are sensitive to the period of the contract, as well as changes in forward interest rate yields.

Debt Devon s fixed-rate debt instruments do not actively trade in an established market. The fair values of this debt are estimated by discounting the principal and interest payments at rates available for debt with similar terms and maturity.

Level 3 Fair Value Measurements

Long-term investments Devon s long-term investments presented in the tables above consisted entirely of auction rate securities. Due to the auction failures discussed in Note 1 and the lack of an active market for Devon s auction rate securities, quoted market prices for these securities were not available as of December 31, 2009 and December 31, 2008. Therefore, Devon used valuation techniques that rely on unobservable, or Level 3, inputs to estimate the fair values of its long-term auction rate securities. These inputs were based on the AAA credit rating of the securities, the probability of full repayment of the securities considering the United States government guarantees of substantially all of the underlying student loans, the collection of all accrued interest to date and continued receipts of principal at par. As a result of using these inputs, Devon concluded the estimated fair values of its long-term auction rate securities approximated the par values as of December 31, 2009 and December 31, 2008. At this time, Devon does not believe the values of its long-term securities are impaired. The changes in these Level 3 assets during 2008 and 2009 consisted entirely of redemptions of principal.

Asset retirement obligations The fair values of the asset retirement obligations are estimated using internal discounted cash flow calculations based upon Devon s estimates of future retirement costs. Reconciliations of the beginning and ending balances of Devon s asset retirement obligations, including revisions of the estimated fair values in 2009 and 2008, are presented in Note 7.

12. Share-Based Compensation

On June 3, 2009, Devon s stockholders adopted the 2009 Long-Term Incentive Plan, which expires on June 2, 2019. This plan authorizes the Compensation Committee, which consists of non-management members of Devon s Board of Directors, to grant nonqualified and incentive stock options, restricted stock awards, Canadian restricted stock units, performance units, stock appreciation rights and cash-out rights to eligible employees. The plan also authorizes the grant of nonqualified stock options, restricted stock awards, restricted stock units and stock appreciation rights to directors. A total of 21.5 million shares of Devon common stock have been reserved for issuance pursuant to the plan. To calculate shares issued under the plan, options granted represent one share and other awards represent 1.84 shares.

Devon also has stock option plans that were adopted in 2005, 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. and Santa Fe Snyder.

With the approval of Devon s Compensation Committee, Devon modified the share-based compensation arrangements for certain of Devon s executives in the second quarter of 2008. The modified compensation arrangements provide that executives who meet certain years-of-service and age criteria can retire and continue vesting in outstanding share-based grants. As a condition to receiving the benefits of these modifications, the executives must agree not to use or disclose Devon s confidential information and not to solicit Devon s employees and customers. The executives are required to agree to these conditions at retirement and again in each subsequent year until all grants have vested.

Although this modification does not accelerate the vesting of the executives grants, it does accelerate the expense recognition as executives approach the years-of-service and age criteria. When the modification was made in the second quarter of 2008, certain executives had already met the years-of-service and age criteria. As a result, Devon recognized an additional $27 million of share-based compensation expense in the second quarter of 2008 related to this modification. This additional expense would have been recognized in future reporting periods if the modification had not been made and the executives continued their employment at Devon.

The following table presents the effects of share-based compensation included in Devon s accompanying statement of operations for the years ended December 31, 2009, 2008 and 2007.

	2009	2008	2007
		(In millions)	
Gross general and administrative expense	$ 209	$ 212	$ 146
Share-based compensation expense capitalized pursuant to the full cost method of accounting for oil and gas properties	$ 66	$ 54	$ 44
Related income tax benefit	$ 43	$ 47	$ 28

Stock Options

Under Devon s 2009 Long-Term Incentive Plan, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. In addition, options granted are exercisable during a period established for each grant, which 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.

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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, 2009, 2008 and 2007. All such amounts represent the weighted-average amounts for each year.

	2009	2008	2007
Grant-date fair value	$ 22.85	$ 21.77	$ 26.43
Volatility factor	47.7%	44.3%	31.6%
Dividend yield	0.9%	0.9%	0.7%
Risk-free interest rate	2.1%	1.2%	5.0%
Expected term (in years)	4.0	3.8	4.0

The following table presents a summary of Devon s outstanding stock options as of December 31, 2009, 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, 2008	11,894	$ 55.16		
Granted	2,026	$ 63.13		
Exercised	(1,497)	$ 31.27		
Forfeited	(263)	$ 71.82		
Outstanding at December 31, 2009	12,160	$ 59.07	3.6	$ 205
Vested and expected to vest at December 31, 2009	12,128	$ 59.05	3.6	$ 204
Exercisable at December 31, 2009	8,371	$ 54.74	2.8	$ 176

The aggregate intrinsic value of stock options that were exercised during 2009, 2008 and 2007 was $51 million, $263 million and $151 million, respectively. As of December 31, 2009, Devon s unrecognized compensation cost related to unvested stock options was $66 million. Such cost is expected to be recognized over a weighted-average period of 2.6 years.

Restricted Stock Awards and Units

Under Devon s 2009 Long-Term Incentive Plan, restricted stock awards and units are subject to the terms, conditions, restrictions and 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 that 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.

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The following table presents a summary of Devon s unvested restricted stock awards as of December 31, 2009, including changes during the year then ended.

	Restricted Stock Awards (In thousands)	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2008	6,334	$ 72.66
Granted	2,656	$ 63.59
Vested	(2,679)	$ 70.16
Forfeited	(146)	$ 73.59
Unvested at December 31, 2009	6,165	$ 69.76

The aggregate fair value of restricted stock awards that vested during 2009, 2008 and 2007 was $165 million, $185 million and $136 million, respectively. As of December 31, 2009, Devon s unrecognized compensation cost related to unvested restricted stock awards and units was $316 million. Such cost is expected to be recognized over a weighted-average period of 2.2 years.

13. Restructuring Costs

In the fourth quarter of 2009, Devon recognized $153 million of estimated employee severance costs associated with the planned divestitures of its offshore assets that was announced in November 2009. This amount was based on estimates of the number of employees that will ultimately be impacted by the divestitures, and includes $63 million related to accelerated vesting of share-based grants. Of the $153 million total, $105 million relates to Devon s U.S. Offshore operations and the remainder relates to its International discontinued operations.

As of the date these financial statements were prepared, only one of the properties Devon intends to sell had actually been sold. Furthermore, the vast majority of employees will not be impacted by the divestitures until the properties are sold. Therefore, Devon s estimate of employee severance costs recognized in the fourth quarter of 2009 was based upon certain key estimates that could change as properties are sold. These estimates include the number of impacted employees, the number of employees offered comparable positions with the buyers and the date of separation for impacted employees.

14. Other Financial Instruments

Until October 31, 2008, Devon owned 14.2 million shares of Chevron common stock. These shares were held in connection with debt owed by Devon that contained an exchange option. The exchange option allowed the debt holders, prior to the debt s maturity of August 15, 2008, to exchange the debt for shares of Chevron common stock owned by Devon. However, Devon had the option to settle any exchanges with cash equal to the market value of

Chevron common stock at the time of the exchange. Devon settled exchange requests during 2008 and 2007 by paying $1.0 billion during 2008 and $0.2 billion during 2007. On October 31, 2008, Devon transferred its 14.2 million shares of Chevron common stock to Chevron. In exchange, Devon received Chevron s interest in the Drunkard s Wash coalbed natural gas field in east-central Utah and $280 million in cash.

The shares of Chevron common stock and the exchange option embedded in the debt were always recorded on Devon s balance sheet at fair value. However, pursuant to accounting rules prior to January 1, 2007, only the change in fair value of the embedded option had historically been included in Devon s results of operations. Conversely, the change in fair value of the Chevron common stock had not been included in Devon s results of operations, but instead had been recorded directly to stockholders equity as part of

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accumulated other comprehensive income. Effective January 1, 2007, under new accounting rules, Devon elected to begin recognizing the change in fair value of the Chevron common stock in its results of operations. Accordingly, beginning with the first quarter of 2007, the change in fair value of the Chevron common stock owned by Devon, along with the change in fair value of the related exchange option, were both included in Devon s results of operations. Also, as a result of this change, Devon reclassified $364 million of after-tax unrealized gains related to Devon s investment in Chevron common stock from accumulated other comprehensive income to retained earnings in the first quarter of 2007.

The following table presents the changes in fair value and cash settlements related to Devon s other financial instruments, as well as its investment in Chevron Common Stock as presented in the accompanying consolidated statements of operations.

	Year Ended December 31, 2009	2008	2007
	(In millions)		
(Gains) and losses from:			
Interest rate swaps fair value changes (See Note 3)	$ (66)	$ (104)	$ (1)
Interest rate swaps settlements (See Note 3)	(40)	(1)	
Chevron common stock		363	(281)
Option embedded in exchangeable debentures		(109)	248
Total	$ (106)	$ 149	$ (34)

15. Reduction of Carrying Value of Oil and Gas Properties

During 2009 and 2008, Devon reduced the carrying values of certain of its oil and gas properties due to full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

	Year Ended December 31, 2009		2008	
	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)			
United States	$ 6,408	$ 4,085	$ 6,538	$ 4,168
Canada			3,353	2,488
Total	$ 6,408	$ 4,085	$ 9,891	$ 6,656

The 2009 reduction was recognized in the first quarter and the 2008 reductions were recognized in the fourth quarter. The reductions resulted from significant decreases in each country s full cost ceiling compared to the immediately preceding quarter. The lower United States ceiling value in the first quarter of 2009 largely resulted from the effects of declining natural gas prices subsequent to December 31, 2008. The lower ceiling values in the fourth quarter of 2008 largely resulted from the effects of sharp declines in oil, gas and NGL prices compared to September 30, 2008.

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16. Other Income

The components of other income include the following:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Interest and dividend income	$ 8	$ 54	$ 48
Reduction of deep water royalties (see Note 10)	84		
Hurricane insurance proceeds (see Note 10)		162	
Other	(24)	1	3
Total	$ 68	$ 217	$ 51

17. Income Taxes

Income Tax (Benefit) Expense

The (loss) earnings from continuing operations before income taxes and the components of income tax (benefit) expense for the years 2009, 2008 and 2007 were as follows:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
(Loss) earnings from continuing operations before income taxes:			
U.S.	$ (4,961)	$ (2,190)	$ 2,642
Canada	435	(1,970)	685
Total	$ (4,526)	$ (4,160)	$ 3,327
Current income tax expense:			
U.S. federal	$ 45	$ 258	$ 83
Various states	18	31	17
Canada and various provinces	178	152	135
Total current tax expense	241	441	235
Deferred income tax (benefit) expense:			

U.S. federal	(1,846)	(875)	745
Various states	(111)	(65)	28
Canada and various provinces	(57)	(622)	(166)
Total deferred tax (benefit) expense	(2,014)	(1,562)	607
Total income tax (benefit) expense	$ (1,773)	$ (1,121)	$ 842

The taxes on the results of discontinued operations presented in the accompanying consolidated statements of operations were all related to Devon s international operations outside North America.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended December 31, 2009	2008 (In millions)	2007
Expected income tax (benefit) expense based on U.S. statutory tax rate of 35%	$ (1,584)	$ (1,456)	$ 1,164
State income taxes	(99)	(29)	30
Taxation on Canadian operations	(31)	227	(10)
Repatriations and tax policy election changes		312	
Canadian statutory rate reduction			(261)
Other	(59)	(175)	(81)
Total income tax (benefit) expense	$ (1,773)	$ (1,121)	$ 842

During 2008, Devon repatriated $2.6 billion from certain foreign subsidiaries to the United States. Also in the second quarter of 2008, Devon made certain tax policy election changes to minimize the taxes Devon otherwise would pay for the cash repatriations, as well as the taxable gains associated with the sales of assets in West Africa. As a result of the repatriations, as well as the tax policy election changes, Devon recognized additional tax expense of $312 million during 2008. Of the $312 million, $295 million was recognized as current income tax expense, and $17 million was recognized as deferred tax expense.

In 2007, deferred income taxes were reduced $261 million due to a Canadian statutory rate reduction that was enacted in that year.

Deferred Tax Assets and Liabilities

The tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities at December 31, 2009 and 2008 are presented below:

	December 31, 2009	2008 (In millions)
Deferred tax assets:		
Net operating loss carryforwards	$ 11	$ 13
Asset retirement obligations	474	442
Pension benefit obligations	130	172
Other	133	74

Total deferred tax assets	748	701
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	(2,315)	(4,163)
Fair value of financial instruments	(108)	(132)
Long-term debt	(162)	(69)
Other	(62)	
Total deferred tax liabilities	(2,647)	(4,364)
Net deferred tax liability	$ (1,899)	$ (3,663)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As shown in the above table, Devon has recognized $748 million of deferred tax assets as of December 31, 2009. Included in total deferred tax assets is $11 million related to various carryforwards available to offset future income taxes. The carryforwards consist of $151 million of state net operating loss carryforwards, which expire primarily between 2010 and 2029. 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 2010 and 2014. Such expectation is based upon current estimates of taxable income during this period, considering limitations on the annual utilization of these benefits as set forth by tax regulations. Significant changes in such estimates caused by variables such as future oil and gas prices or capital expenditures could alter the timing of the eventual utilization of such carryforwards. There can be no assurance that Devon will generate any specific level of continuing taxable earnings. However, management believes that Devon s future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

Unrecognized Tax Benefits

The following table presents changes in Devon s unrecognized tax benefits for the year ended December 31, 2009 (in millions).

Balance as of December 31, 2008	$ 260
Increases (decreases) due to:	
Tax positions taken in current year	20
Accrual of interest related to tax positions taken	7
Lapse of statute of limitations	(15)
Settlements	(5)
Foreign currency translation	5
Balance as of December 31, 2009	$ 272

Devon s unrecognized tax benefit balance at December 31, 2009 and 2008 included $35 million and $29 million of interest and penalties, respectively. If recognized, all of Devon s unrecognized tax benefits as of December 31, 2009 would affect Devon s effective income tax rate.

Included below is a summary of the tax years, by jurisdiction, that remain subject to examination by taxing authorities.

Jurisdiction	Tax Years Open
U.S. federal	2005-2009
Various U.S. states	2005-2009

Canada federal	2001-2009
Various Canadian provinces	2001-2009

Certain statute of limitation expirations are scheduled to occur in the next twelve months. However, Devon is currently in various stages of the administrative review process for certain open tax years. In addition, Devon is currently subject to various income tax audits that have not reached the administrative review process. As a result, Devon cannot reasonably anticipate the extent that the liabilities for unrecognized tax benefits will increase or decrease within the next twelve months.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Discontinued Operations

For the three-year period ended December 31, 2009, Devon s discontinued operations include amounts related to its assets in Azerbaijan, Brazil, China and other minor International properties that it is in the process of divesting. Additionally, during 2007 and 2008, Devon s discontinued operations included amounts related to its assets in Egypt and West Africa, including Equatorial Guinea, Cote d Ivoire, Gabon and other countries in the region, until they were sold.

Devon s African sales generated total proceeds of $3.0 billion. The following table presents the gains on the African divestiture transactions by year.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net of Taxes	Gross	Net of Taxes	Gross	Net of Taxes
	(In millions)					
Egypt	$	$	$	$	$ 90	$ 90
Equatorial Guinea			619	544		
Gabon			117	122		
Cote d Ivoire	17	17	83	95		
Other				8		
Total	$ 17	$ 17	$ 819	$ 769	$ 90	$ 90

Revenues related to Devon s discontinued operations totaled $945 million, $1.7 billion and $2.2 billion during 2009, 2008 and 2007, respectively. Earnings from discontinued operations before income taxes totaled $322 million, $1.3 billion and $1.6 billion during 2009, 2008 and 2007, respectively.

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table presents the main classes of assets and liabilities associated with Devon s discontinued operations as of December 31, 2009 and 2008.

	December 31, 2009	December 31, 2008
	(In millions)	
Assets:		
Cash and cash equivalents	$ 365	$ 189
Accounts receivable	165	112
Other current assets	127	91
Current assets	$ 657	$ 392
Property and equipment, net of accumulated depreciation, depletion and amortization	$ 1,099	$ 954
Goodwill	68	68
Other long-term assets	83	106
Total long-term assets	$ 1,250	$ 1,128
Liabilities:		
Accounts payable	$ 158	$ 220
Other current liabilities	76	145
Current liabilities	$ 234	$ 365
Asset retirement obligations, long-term	$ 109	$ 98
Deferred income taxes	101	65
Other liabilities	3	3
Long-term liabilities	$ 213	$ 166

Reductions of Carrying Value of Oil and Gas Properties

During 2009, 2008 and 2007, Devon reduced the carrying values of certain of its oil and gas properties that are now held for sale. These reductions primarily resulted from full cost ceiling limitations. A summary of these reductions and additional discussion is provided below.

Year Ended December 31,					
2009		2008		2007	
	Net of		Net of		Net of

	Gross	Taxes	Gross	Taxes	Gross	Taxes
	(In millions)		(In millions)		(In millions)	
Brazil	$ 103	$ 103	$ 437	$ 437	$	$
Nigeria					68	13
Other	5	2	57	28		
Total	$ 108	$ 105	$ 494	$ 465	$ 68	$ 13

Brazil s 2009 reduction resulted largely from an exploratory well drilled at the BM-BAR-3 block in the offshore Barreirinhas Basin. After drilling this well in the first quarter of 2009, Devon concluded that the well did not have adequate reserves for commercial viability. As a result, the seismic, leasehold and drilling costs associated with this well contributed to the reduction recognized in the first quarter of 2009.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Brazil s 2008 reduction was recognized in the fourth quarter of 2008 and resulted primarily from a significant decrease in its full cost ceiling. The lower ceiling value largely resulted from the effects of sharp declines in oil prices compared to previous quarter-end prices.

Based on unsuccessful drilling activities in Nigeria, Devon reduced the carrying value of its Nigerian oil and gas properties in 2007.

19. (Loss) Earnings Per Share

The following table reconciles earnings from continuing operations and common shares outstanding used in the calculations of basic and diluted (loss) earnings per share for 2009, 2008 and 2007. Because a net loss from continuing operations was incurred during 2009 and 2008, the dilutive shares produce an antidilutive net loss per share result. Therefore, the diluted loss per share from continuing operations reported in the accompanying 2009 and 2008 consolidated statements of operations are the same as the basic loss per share amounts.

	(Loss) Earnings	Common Shares	(Loss) Earnings per Share
	(In millions, except per share amounts)		
Year Ended December 31, 2009:			
Loss from continuing operations	$ (2,753)	444	
Attributable to participating securities	31	(5)	
Basic and diluted loss per share	$ (2,722)	439	$ (6.20)
Year Ended December 31, 2008:			
Loss from continuing operations	$ (3,039)	444	
Attributable to participating securities	31	(5)	
Less preferred stock dividends	(5)		
Basic and diluted loss per share	$ (3,013)	439	$ (6.86)
Year Ended December 31, 2007:			
Earnings from continuing operations	$ 2,485	445	
Attributable to participating securities	(23)	(4)	
Less preferred stock dividends	(10)		
Basic earnings per share	2,452	441	$ 5.56
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options		5	

Diluted earnings per share	$ 2,452	446	$ 5.50

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 9 million, 5 million and 2 million in 2009, 2008 and 2007, respectively.

20. Segment Information

Devon manages its operations through seven distinct operating segments, or divisions, which are defined primarily by geographic areas. For financial reporting purposes, Devon aggregates its United States divisions into one reporting segment due to the similar nature of the business. However, Devon s Canadian and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

International divisions are reported as separate reporting segments primarily due to significant differences in the respective regulatory environments.

Devon s segments are all primarily engaged in oil and gas producing activities, and certain information regarding such activities for each segment is included in Note 22. Following is certain financial information regarding Devon s segments for 2009, 2008 and 2007. The revenues reported are all from external customers.

	U.S.	Canada	International	Total
		(In millions)		
As of December 31, 2009:				
Current assets, including current assets held for sale	$ 1,449	$ 886	$ 657	$ 2,992
Property and equipment, net	13,199	5,568		18,767
Goodwill	3,046	2,884		5,930
Other assets, including long-term assets held for sale	674	73	1,250	1,997
Total assets	$ 18,368	$ 9,411	$ 1,907	$ 29,686
Current liabilities, including current liabilities held for sale	$ 2,993	$ 575	$ 234	$ 3,802
Long-term debt	2,866	2,981		5,847
Asset retirement obligations, long-term	754	664		1,418
Other liabilities, including long-term liabilities held for sale	890	47	213	1,150
Deferred income taxes	860	1,039		1,899
Stockholders equity	10,005	4,105	1,460	15,570
Total liabilities and stockholders equity	$ 18,368	$ 9,411	$ 1,907	$ 29,686

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada (In millions)	Total
Year Ended December 31, 2009:			
Revenues:			
Oil, gas and NGL sales	$ 3,958	$ 2,139	$ 6,097
Net gain on oil and gas derivative financial instruments	382	2	384
Marketing and midstream revenues	1,498	36	1,534
Total revenues	5,838	2,177	8,015
Expenses and other income, net:			
Lease operating expenses	997	673	1,670
Taxes other than income taxes	278	36	314
Marketing and midstream operating costs and expenses	1,004	18	1,022
Depreciation, depletion and amortization of oil and gas properties	1,247	585	1,832
Depreciation and amortization of non-oil and gas properties	251	25	276
Accretion of asset retirement obligations	53	38	91
General and administrative expenses	529	119	648
Restructuring costs	105		105
Interest expense	125	224	349
Change in fair value of other financial instruments	(106)		(106)
Reduction of carrying value of oil and gas properties	6,408		6,408
Other (income) expense, net	(92)	24	(68)
Total expenses and other income, net	10,799	1,742	12,541
(Loss) earnings from continuing operations before income taxes	(4,961)	435	(4,526)
Income tax (benefit) expense:			
Current	63	178	241
Deferred	(1,957)	(57)	(2,014)
Total income tax (benefit) expense	(1,894)	121	(1,773)
(Loss) earnings from continuing operations	$ (3,067)	$ 314	$ (2,753)
Capital expenditures, before revision of future asset retirement obligations	$ 3,536	$ 1,114	$ 4,650
Revision of future asset retirement obligations	48	(15)	33
Capital expenditures, continuing operations	$ 3,584	$ 1,099	$ 4,683

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada	International	Total
		(In millions)		
As of December 31, 2008:				
Current assets, including current assets held for sale	$ 1,925	$ 367	$ 392	$ 2,684
Property and equipment, net	17,676	4,355		22,031
Goodwill	3,046	2,465		5,511
Other assets, including long-term assets held for sale	482	72	1,128	1,682
Total assets	$ 23,129	$ 7,259	$ 1,520	$ 31,908
Current liabilities, including current liabilities held for sale	$ 2,227	$ 543	$ 365	$ 3,135
Long-term debt	2,683	2,978		5,661
Asset retirement obligations, long-term	694	555		1,249
Other liabilities, including long-term liabilities held for sale	983	40	166	1,189
Deferred income taxes	2,734	880		3,614
Stockholders equity	13,808	2,263	989	17,060
Total liabilities and stockholders equity	$ 23,129	$ 7,259	$ 1,520	$ 31,908

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada (In millions)	Total
Year Ended December 31, 2008:			
Revenues:			
Oil, gas and NGL sales	$ 8,206	$ 3,514	$ 11,720
Net loss on oil and gas derivative financial instruments	(154)		(154)
Marketing and midstream revenues	2,247	45	2,292
Total revenues	10,299	3,559	13,858
Expenses and other income, net:			
Lease operating expenses	1,075	776	1,851
Taxes other than income taxes	438	38	476
Marketing and midstream operating costs and expenses	1,593	18	1,611
Depreciation, depletion and amortization of oil and gas properties	1,998	950	2,948
Depreciation and amortization of non-oil and gas Properties	229	26	255
Accretion of asset retirement obligations	42	38	80
General and administrative expenses	513	132	645
Interest expense	117	212	329
Change in fair value of other financial instruments	149		149
Reduction of carrying value of oil and gas properties	6,538	3,353	9,891
Other income, net	(203)	(14)	(217)
Total expenses and other income, net	12,489	5,529	18,018
Loss from continuing operations before income taxes	(2,190)	(1,970)	(4,160)
Income tax (benefit) expense:			
Current	289	152	441
Deferred	(940)	(622)	(1,562)
Total income tax benefit	(651)	(470)	(1,121)
Loss from continuing operations	$ (1,539)	$ (1,500)	$ (3,039)
Capital expenditures, before revision of future asset retirement obligations	$ 8,313	$ 1,639	$ 9,952
Revision of future asset retirement obligations	152	73	225
Capital expenditures, continuing operations	$ 8,465	$ 1,712	$ 10,177

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	U.S.	Canada (In millions)	Total
Year Ended December 31, 2007:			
Revenues:			
Oil, gas and NGL sales	$ 5,814	$ 2,411	$ 8,225
Net gain on oil and gas derivative financial instruments	14		14
Marketing and midstream revenues	1,693	43	1,736
Total revenues	7,521	2,454	9,975
Expenses and other income, net:			
Lease operating expenses	905	627	1,532
Taxes other than income taxes	327	31	358
Marketing and midstream operating costs and expenses	1,200	17	1,217
Depreciation, depletion and amortization of oil and gas properties	1,672	740	2,412
Depreciation and amortization of non-oil and gas properties	180	21	201
Accretion of asset retirement obligations	38	32	70
General and administrative expenses	395	118	513
Interest expense	228	202	430
Change in fair value of other financial instruments	(32)	(2)	(34)
Other income, net	(34)	(17)	(51)
Total expenses and other income, net	4,879	1,769	6,648
Earnings from continuing operations before income taxes	2,642	685	3,327
Income tax expense (benefit):			
Current	100	135	235
Deferred	773	(166)	607
Total income tax expense (benefit)	873	(31)	842
Earnings from continuing operations	$ 1,769	$ 716	$ 2,485
Capital expenditures, before revision of future asset retirement obligations	$ 4,522	$ 1,350	$ 5,872
Revision of future asset retirement obligations	210	99	309
Capital expenditures, continuing operations	$ 4,732	$ 1,449	$ 6,181

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

21. Supplemental Information to Statements of Cash Flows

Additional information related to Devon s 2009, 2008 and 2007 statements of cash flows are presented below:

	Year Ended December 31, 2009	2008	2007
	(In millions)		
Net decrease (increase) in working capital:			
Decrease (increase) in accounts receivable	$ 142	$ 187	$ (286)
Decrease (increase) in other current assets	212	(46)	(31)
(Decrease) increase in accounts payable	(91)	159	45
Increase in revenues and royalties due to others		11	79
Decrease in income taxes payable	(48)	(309)	(80)
Decrease in other current liabilities	(66)	(209)	(239)
Net decreases (increase) in working capital	$ 149	$ (207)	$ (512)
Supplementary cash flow data:			
Interest paid (net of capitalized interest)	$ 314	$ 336	$ 406
Income taxes paid (continuing and discontinued operations)	$ 68	$ 1,436	$ 588
Noncash investing activity exchange of investment in Chevron common stock for oil and gas properties	$	$ 610	$

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

Supplemental unaudited information regarding Devon s oil and gas activities is presented in this note. The information is provided separately by country and continent. Additionally, the costs incurred and reserves information for the United States is segregated between Devon s onshore and offshore operations. Unless otherwise noted, this supplemental information excludes amounts for all periods presented related to Devon s discontinued operations.

Costs Incurred

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

	Year Ended December 31, 2009				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
			(In millions)		

Property acquisition costs:					
Proved properties	$ 17	$	$ 17	$ 18	$ 35
Unproved properties	52	11	63	72	135
Exploration costs	122	260	382	152	534
Development costs	2,011	537	2,548	835	3,383
Costs incurred	$ 2,202	$ 808	$ 3,010	$ 1,077	$ 4,087

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended December 31, 2008				
	U.S. Onshore	U.S. Offshore	Total U.S. (In millions)	Canada	North America
Property acquisition costs:					
Proved properties	$ 822	$	$ 822	$	$ 822
Unproved properties	1,226	185	1,411	352	1,763
Exploration costs	206	638	844	173	1,017
Development costs	4,182	551	4,733	1,131	5,864
Costs incurred	$ 6,436	$ 1,374	$ 7,810	$ 1,656	$ 9,466

	Year Ended December 31, 2007				
	U.S. Onshore	U.S. Offshore	Total U.S. (In millions)	Canada	North America
Property acquisition costs:					
Proved properties	$ 3	$	$ 3	$ 7	$ 10
Unproved properties	77	79	156	49	205
Exploration costs	195	374	569	211	780
Development costs	3,183	359	3,542	1,098	4,640
Costs incurred	$ 3,458	$ 812	$ 4,270	$ 1,365	$ 5,635

Pursuant to the full cost method of accounting, Devon capitalizes certain of its general and administrative expenses that are related to property acquisition, exploration and development activities. Such capitalized expenses, which are included in the costs shown in the preceding tables, were $332 million, $337 million and $277 million in the years 2009, 2008 and 2007, 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 $74 million, $71 million and $48 million in the years 2009, 2008 and 2007, respectively.

Results of Operations

The following tables include revenues and expenses directly associated 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

	Year Ended December 31, 2009		
	United States	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$ 3,958	$ 2,139	$ 6,097
Lease operating expenses	(997)	(673)	(1,670)
Taxes other than income taxes	(258)	(35)	(293)
Depreciation, depletion and amortization	(1,247)	(585)	(1,832)
Accretion of asset retirement obligations	(53)	(38)	(91)
General and administrative expenses	(145)	(74)	(219)
Reduction of carrying value of oil and gas properties	(6,408)		(6,408)
Income tax benefit (expense)	1,800	(220)	1,580
Results of operations	$ (3,350)	$ 514	$ (2,836)
Depreciation, depletion and amortization per Boe	$ 7.47	$ 8.84	$ 7.86

	Year Ended December 31, 2008		
	United States	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$ 8,206	$ 3,514	$ 11,720
Lease operating expenses	(1,075)	(776)	(1,851)
Taxes other than income taxes	(420)	(37)	(457)
Depreciation, depletion and amortization	(1,998)	(950)	(2,948)
Accretion of asset retirement obligations	(42)	(38)	(80)
General and administrative expenses	(148)	(87)	(235)
Reduction of carrying value of oil and gas properties	(6,538)	(3,353)	(9,891)
Income tax benefit	719	405	1,124
Results of operations	$ (1,296)	$ (1,322)	$ (2,618)
Depreciation, depletion and amortization per Boe	$ 12.31	$ 15.59	$ 13.20

	Year Ended December 31, 2007		
	United States	Canada	North America
		(In millions)	
Oil, gas and NGL sales	$ 5,814	$ 2,411	$ 8,225
Lease operating expenses	(905)	(627)	(1,532)
Taxes other than income taxes	(312)	(31)	(343)
Depreciation, depletion and amortization	(1,672)	(740)	(2,412)
Accretion of asset retirement obligations	(38)	(32)	(70)
General and administrative expenses	(143)	(76)	(219)
Income tax expense	(966)	(49)	(1,015)
Results of operations	$ 1,778	$ 856	$ 2,634
Depreciation, depletion and amortization per Boe	$ 11.44	$ 12.73	$ 11.81

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 2007, the total and Canadian income tax amounts in the table above were reduced by $261 million due to statutory rate reductions that were enacted in that year.

Proved Reserves

The following tables present Devon s estimated proved developed and proved undeveloped reserves by product for each significant country for the three years ended December 31, 2009. The significant changes in Devon s reserves are discussed following the tables.

	Oil (MMBbls)				
	U.S. Onshore	**U.S. Offshore**	**Total U.S.**	**Canada**	**North America**
Proved developed and undeveloped reserves:					
December 31, 2006	127	43	170	329	499
Revisions due to prices	4		4	16	20
Revisions other than price	3	3	6	13	19
Extensions and discoveries	8	1	9	46	55
Purchase of reserves	1		1		1
Production	(11)	(8)	(19)	(16)	(35)
Sale of reserves	(1)		(1)		(1)
December 31, 2007	131	39	170	388	558
Revisions due to prices	(17)	(3)	(20)	(349)	(369)
Revisions other than price	2	3	5	2	7
Extensions and discoveries	11	1	12	120	132
Purchase of reserves	18		18		18
Production	(11)	(6)	(17)	(22)	(39)
Sale of reserves	(1)		(1)	(5)	(6)
December 31, 2008	133	34	167	134	301
Revisions due to prices	9	2	11	291	302
Revisions other than price		1	1	(8)	(7)
Extensions and discoveries	9	2	11	122	133
Purchase of reserves					
Production	(12)	(5)	(17)	(25)	(42)
Sale of reserves		(1)	(1)		(1)
December 31, 2009	139	33	172	514	686
Proved developed reserves as of:					
December 31, 2006	116	31	147	112	259
December 31, 2007	122	26	148	195	343

December 31, 2008	111	22	133	110	243
December 31, 2009	119	21	140	149	289
Proved undeveloped reserves as of:					
December 31, 2006	11	12	23	217	240
December 31, 2007	9	13	22	193	215
December 31, 2008	22	12	34	24	58
December 31, 2009	20	12	32	365	397

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Gas (Bcf)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2006	5,979	376	6,355	1,896	8,251
Revisions due to prices	117	2	119	50	169
Revisions other than price	175	(1)	174	(19)	155
Extensions and discoveries	1,055	78	1,133	139	1,272
Purchase of reserves	10		10	5	15
Production	(558)	(77)	(635)	(227)	(862)
Sale of reserves	(13)		(13)		(13)
December 31, 2007	6,765	378	7,143	1,844	8,987
Revisions due to prices	(367)	(2)	(369)	(219)	(588)
Revisions other than price	85	21	106	(12)	94
Extensions and discoveries	1,916	50	1,966	111	2,077
Purchase of reserves	250		250	2	252
Production	(669)	(57)	(726)	(212)	(938)
Sale of reserves	(1)		(1)	(4)	(5)
December 31, 2008	7,979	390	8,369	1,510	9,879
Revisions due to prices	(661)	(4)	(665)	(29)	(694)
Revisions other than price	119	(62)	57	(14)	43
Extensions and discoveries	1,387	64	1,451	67	1,518
Purchase of reserves	1		1	6	7
Production	(698)	(45)	(743)	(223)	(966)
Sale of reserves		(1)	(1)	(29)	(30)
December 31, 2009	8,127	342	8,469	1,288	9,757
Proved developed reserves as of:					
December 31, 2006	4,672	244	4,916	1,560	6,476
December 31, 2007	5,547	196	5,743	1,506	7,249
December 31, 2008	6,469	212	6,681	1,357	8,038
December 31, 2009	6,447	185	6,632	1,213	7,845
Proved undeveloped reserves as of:					
December 31, 2006	1,307	132	1,439	336	1,775
December 31, 2007	1,218	182	1,400	338	1,738
December 31, 2008	1,510	178	1,688	153	1,841
December 31, 2009	1,680	157	1,837	75	1,912

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Natural Gas Liquids (MMBbls)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2006	230	3	233	42	275
Revisions due to prices	5		5		5
Revisions other than price	22	(1)	21	(1)	20
Extensions and discoveries	45		45	2	47
Purchase of reserves					
Production	(21)	(1)	(22)	(4)	(26)
Sale of reserves					
December 31, 2007	281	1	282	39	321
Revisions due to prices	(18)		(18)	(2)	(20)
Revisions other than price	5	1	6		6
Extensions and discoveries	65		65	2	67
Purchase of reserves	6		6		6
Production	(24)		(24)	(4)	(28)
Sale of reserves					
December 31, 2008	315	2	317	35	352
Revisions due to prices	(11)		(11)	2	(9)
Revisions other than price	36	1	37		37
Extensions and discoveries	70		70	1	71
Purchase of reserves					
Production	(25)	(1)	(26)	(4)	(30)
Sale of reserves					
December 31, 2009	385	2	387	34	421
Proved developed reserves as of:					
December 31, 2006	194	2	196	33	229
December 31, 2007	243	1	244	30	274
December 31, 2008	260	1	261	31	292
December 31, 2009	293	1	294	32	326
Proved undeveloped reserves as of:					
December 31, 2006	36	1	37	9	46
December 31, 2007	38		38	9	47
December 31, 2008	55	1	56	4	60
December 31, 2009	92	1	93	2	95

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total (MMBoe)(1)				
	U.S. Onshore	U.S. Offshore	Total U.S.	Canada	North America
Proved developed and undeveloped reserves:					
December 31, 2006	1,353	109	1,462	687	2,149
Revisions due to prices	28	1	29	25	54
Revisions other than price	55	1	56	7	63
Extensions and discoveries	228	14	242	72	314
Purchase of reserves	2		2	1	3
Production	(124)	(22)	(146)	(58)	(204)
Sale of reserves	(3)		(3)		(3)
December 31, 2007	1,539	103	1,642	734	2,376
Revisions due to prices	(97)	(3)	(100)	(387)	(487)
Revisions other than price	21	7	28		28
Extensions and discoveries	395	10	405	141	546
Purchase of reserves	66		66		66
Production	(146)	(16)	(162)	(61)	(223)
Sale of reserves	(1)		(1)	(6)	(7)
December 31, 2008	1,777	101	1,878	421	2,299
Revisions due to prices	(113)	1	(112)	289	177
Revisions other than price	57	(8)	49	(11)	38
Extensions and discoveries	311	12	323	135	458
Purchase of reserves				1	1
Production	(154)	(13)	(167)	(66)	(233)
Sale of reserves		(1)	(1)	(6)	(7)
December 31, 2009	1,878	92	1,970	763	2,733
Proved developed reserves as of:					
December 31, 2006	1,089	74	1,163	405	1,568
December 31, 2007	1,290	59	1,349	476	1,825
December 31, 2008	1,449	59	1,508	367	1,875
December 31, 2009	1,486	53	1,539	383	1,922
Proved undeveloped reserves as of:					
December 31, 2006	264	35	299	282	581
December 31, 2007	249	44	293	258	551
December 31, 2008	328	42	370	54	424
December 31, 2009	392	39	431	380	811

(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 gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to Boe on a one-to-one basis with oil.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

SEC s Modernization of Oil and Gas Reporting

At the end of 2009, Devon adopted the SEC s *Modernization of Oil and Gas Reporting*, as well as the conforming rule changes issued by the Financial Accounting Standards Board. Upon adoption, the two primary rule changes that impacted Devon s year-end reserves estimates were those related to assumptions for pricing and reasonable certainty.

The SEC s prior rules required proved reserve estimates to be calculated using prices as of the end of the period and held constant over the life of the reserves. The revised rules require reserves estimates to be calculated using an average of the first-day-of-the-month price for the preceding 12-month period.

The revised rules amend the definition of proved reserves to permit the use of reliable technologies to establish the reasonable certainty of proved reserves. This revision includes provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations. This revision also allows proved reserves to be claimed beyond development spacing areas that are immediately adjacent to developed spacing areas if economic producibility can be established with reasonable certainty based on reliable technologies. As a result of adopting these provisions of the new rules, Devon s 2009 reserves increased approximately 65 MMBoe, or 2%. This increase is included in the 2009 extensions and discoveries total.

Price Revisions

2009 Reserves increased 177 MMBoe due to higher oil prices, partially offset by lower gas prices. The increase in oil reserves primarily related to Devon s Jackfish thermal heavy oil reserves in Canada. At the end of 2008, 331 MMBoe of reserves related to Jackfish were not considered proved. However, due to higher prices, these reserves were considered proved as of December 31, 2009. Significantly lower gas prices caused Devon s reserves to decrease 116 MMBoe, which primarily related to its United States reserves.

2008 Due to significantly lower oil, gas and NGL prices as of December 31, 2008 compared to December 31, 2007, 487 MMBoe of reserves were not considered proved as of December 31, 2008. Of the 487 MMBoe price revisions, 331 MMBoe related to Jackfish steam-assisted gravity drainage project in Canada.

The 487 MMBoe price revision also included 28 MMBoe related to Devon s proved reserves in the Canadian province of Alberta. In December 2008, the provincial government of Alberta enacted a new royalty regime. The new regime for conventional oil, gas, NGL and heavy oil production was effective January 1, 2009. As a result of the newly enacted royalties, Devon s proved reserves decreased as of December 31, 2008.

Revisions Other Than Price

The 2009 total revision included 48 MMBoe related to the Barnett Shale. The 2008 total included performance revisions of 22 MMBoe in the Barnett Shale. The 2007 total included performance revisions of 39 MMBoe at the Barnett Shale, 13 MMBoe at Jackfish and 13 MMBoe at Carthage.

Extensions and Discoveries

2009 Of the 458 MMBoe of 2009 extensions and discoveries, 204 MMBoe related to the Barnett Shale area in Texas, 118 MMBoe related to Jackfish, 49 MMBoe related to the Cana-Woodford Shale area in western Oklahoma, 14 MMBoe related to the Rocky Mountain area, 11 MMBoe related to Deepwater Production in the Gulf, 8 MMBoe related to the Carthage Conventional area in east Texas, and 7 MMBoe related to the Haynesville Shale area in east Texas.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The 2009 extensions and discoveries included 371 MMBoe related to additions from Devon s infill drilling activities, including 203 MMBoe at the Barnett Shale, 118 MMBoe at Jackfish and 24 MMBoe at the Cana-Woodford Shale.

2008 Of the 546 MMBoe of 2008 extensions and discoveries, 252 MMBoe related to the Barnett Shale, 101 MMBoe related to Jackfish, 44 MMBoe related to Carthage Conventional, 21 MMBoe related to the Cana-Woodford Shale, 19 MMBoe related to the Lloydminster heavy oil development in Canada and 17 MMBoe related to the Arkoma-Woodford Shale area in southeastern Oklahoma.

The 2008 extensions and discoveries included 420 MMBoe related to additions from Devon s infill drilling activities, including 243 MMBoe at the Barnett Shale, 101 MMBoe at Jackfish, 22 MMBoe at Carthage Conventional, 18 MMBoe at Lloydminster and 11 MMBoe at the Cana-Woodford Shale.

2007 Of the 314 MMBoe of 2007 extensions and discoveries, 119 MMBoe related to the Barnett Shale, 34 MMBoe related to Carthage, 22 MMBoe related to Jackfish, 20 MMBoe related to Lloydminster, 17 MMBoe related to Washakie and 15 MMBoe related to the Arkoma-Woodford Shale.

The 2007 extensions and discoveries included 154 MMBoe related to additions from Devon s infill drilling activities, including 96 MMBoe at the Barnett Shale and 19 MMBoe at Lloydminster.

Purchase of Reserves

The 2008 total included 34 MMBoe located in Utah and 27 MMBoe located in the Permian Basin.

Prepared and Audited Reserves

Set forth below is a summary of the reserves that were evaluated, either by preparation or audit, by independent petroleum consultants for each of the years ended 2009, 2008 and 2007.

	2009		**2008**		**2007**	
	Prepared	**Audited**	**Prepared**	**Audited**	**Prepared**	**Audited**
U.S. Onshore		93%		92%		88%
U.S. Offshore	100%		100%		100%	
U.S.	5%	89%	5%	87%	6%	82%
Canada		91%		78%	34%	51%
North America	3%	89%	4%	85%	15%	73%

Prepared reserves are those quantities of reserves that were prepared by an independent petroleum consultant. Audited reserves are those quantities of reserves that 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.

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Standardized Measure

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

	Year Ended December 31, 2009		
	United States	Canada (In millions)	North America
Future cash inflows	$ 44,571	$ 28,442	$ 73,013
Future costs:			
Development	(6,814)	(4,132)	(10,946)
Production	(22,184)	(9,847)	(32,031)
Future income tax expense	(3,572)	(3,408)	(6,980)
Future net cash flows	12,001	11,055	23,056
10% discount to reflect timing of cash flows	(6,121)	(5,532)	(11,653)
Standardized measure of discounted future net cash flows	$ 5,880	$ 5,523	$ 11,403

	Year Ended December 31, 2008		
	United States	Canada (In millions)	North America
Future cash inflows	$ 51,284	$ 11,459	$ 62,743
Future costs:			
Development	(6,887)	(1,623)	(8,510)
Production	(24,113)	(5,742)	(29,855)
Future income tax expense	(5,585)	(942)	(6,527)
Future net cash flows	14,699	3,152	17,851
10% discount to reflect timing of cash flows	(7,318)	(1,140)	(8,458)
Standardized measure of discounted future net cash flows	$ 7,381	$ 2,012	$ 9,393

	Year Ended December 31, 2007	
	Canada	North America

	United States		
		(In millions)	
Future cash inflows	$ 72,109	$ 28,684	$ 100,793
Future costs:			
Development	(5,673)	(3,380)	(9,053)
Production	(24,606)	(10,941)	(35,547)
Future income tax expense	(12,704)	(3,570)	(16,274)
Future net cash flows	29,126	10,793	39,919
10% discount to reflect timing of cash flows	(14,312)	(5,025)	(19,337)
Standardized measure of discounted future net cash flows	$ 14,814	$ 5,768	$ 20,582

Future cash inflows, development costs and production costs were computed using the same assumptions for prices and costs that were used to estimate Devon s proved oil and gas reserves at the end of each year. For 2009, the prices averaged $47.80 per barrel of oil, $3.12 per Mcf of gas and $22.78 per barrel of natural

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

gas liquids. Of the $10.9 billion of future development costs as of the end of 2009, $2.0 billion, $1.6 billion and $0.9 billion are estimated to be spent in 2010, 2011 and 2012, respectively.

Future development costs include not only development costs, but also future dismantlement, abandonment and rehabilitation costs. Included as part of the $10.9 billion of future development costs are $1.1 billion of future dismantlement, abandonment and rehabilitation costs.

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

The 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, 2009	2008	2007
	(In millions)		
Beginning balance	$ 9,393	$ 20,582	$ 13,474
Oil, gas and NGL sales, net of production costs	(3,915)	(9,177)	(6,131)
Net changes in prices and production costs	(1,672)	(13,839)	7,896
Extensions and discoveries, net of future development costs	2,378	1,729	4,130
Purchase of reserves, net of future development costs	6	214	50
Development costs incurred that reduced future development costs	1,012	1,660	1,559
Revisions of quantity estimates	4,051	(1,294)	564
Sales of reserves in place	(37)	(2)	(51)
Accretion of discount	1,281	2,894	1,933
Net change in income taxes	(51)	4,934	(2,494)
Other, primarily changes in timing and foreign exchange rates	(1,043)	1,692	(348)
Ending balance	$ 11,403	$ 9,393	$ 20,582

DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

23. Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the unaudited interim results of operations for the years ended December 31, 2009 and 2008.

	2009				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$ 1,900	$ 1,822	$ 1,848	$ 2,445	$ 8,015
(Loss) earnings from continuing operations	$ (3,882)	$ 190	$ 382	557	$ (2,753)
(Loss) earnings from discontinued operations	(77)	124	117	110	274
Net (loss) earnings	$ (3,959)	$ 314	$ 499	$ 667	$ (2,479)
Basic net (loss) earnings per common share:					
(Loss) earnings from continuing operations	$ (8.74)	$ 0.43	$ 0.86	$ 1.25	$ (6.20)
(Loss) earnings from discontinued operations	(0.18)	0.28	0.27	0.25	0.62
Net (loss) earnings	$ (8.92)	$ 0.71	$ 1.13	$ 1.50	$ (5.58)
Diluted net (loss) earnings per common share:					
(Loss) earnings from continuing operations	$ (8.74)	$ 0.42	$ 0.86	$ 1.25	$ (6.20)
(Loss) earnings from discontinued operations	(0.18)	0.28	0.26	0.24	0.62
Net (loss) earnings	$ (8.92)	$ 0.70	$ 1.12	$ 1.49	$ (5.58)

	2008				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
	(In millions, except per share amounts)				
Revenues	$ 2,503	$ 3,152	$ 5,651	$ 2,552	$ 13,858
Earnings (loss) from continuing operations	$ 415	$ 423	$ 2,393	(6,270)	$ (3,039)
Earnings (loss) from discontinued operations	334	878	225	(546)	891

Net earnings (loss)	$ 749	$ 1,301	$ 2,618	$ (6,816)	$ (2,148)
Basic net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 0.93	$ 0.94	$ 5.42	$ (14.19)	$ (6.86)
Earnings (loss) from discontinued operations	0.75	1.97	0.51	(1.23)	2.01
Net earnings (loss)	$ 1.68	$ 2.91	$ 5.93	$ (15.42)	$ (4.85)
Diluted net earnings (loss) per common share:					
Earnings (loss) from continuing operations	$ 0.92	$ 0.93	$ 5.37	$ (14.19)	$ (6.86)
Earnings (loss) from discontinued operations	0.74	1.95	0.51	(1.23)	2.01
Net earnings (loss)	$ 1.66	$ 2.88	$ 5.88	$ (15.42)	$ (4.85)

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DEVON ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings (Loss) from Continuing Operations

The first quarter of 2009 includes a reduction of the carrying values of United States oil and gas properties totaling $6.4 billion ($4.1 billion after income taxes, or $9.20 per diluted share).

The fourth quarter of 2009 includes restructuring costs that relate to Devon s planned asset divestitures and total $105 million ($67 million after income taxes, or $0.15 per diluted share).

The first and second quarters of 2008 include unrealized losses on Devon s commodity hedges of $780 million ($499 million after income taxes, or $1.11 per diluted share) and $912 million ($584 million after income taxes, or $1.30 per diluted share), respectively, as a result of increases in gas prices subsequent to the trade dates. The third quarter of 2008 includes a net unrealized gain of $1.8 billion ($1.2 billion after income taxes, or $2.63 per diluted share), resulting from a decrease in gas prices.

The second quarter of 2008 includes an increase to income tax expense of $312 million (or $0.70 per diluted share) due to repatriations from certain foreign subsidiaries to the United States and tax policy election changes.

The fourth quarter of 2008 includes reductions of the carrying values of United States and Canadian oil and gas properties totaling $9.9 billion ($6.7 billion after income taxes, or $15.06 per diluted share).

Earnings (Loss) from Discontinued Operations

The first quarter of 2009 includes reductions of the carrying values of oil and gas properties totaling $108 million ($105 million after income taxes, or $0.24 per diluted share).

The fourth quarter of 2009 includes restructuring costs that relate to Devon s planned asset divestitures and total $48 million ($31 million after income taxes, or $0.07 per diluted share).

The second quarter of 2008 includes a $623 million gain ($529 million after income taxes, or $1.17 per diluted share) as a result of completing the sale of Devon s Equatorial Guinea operations. Also, during the second quarter of 2008, Devon closed the sale of its Gabon operations, which resulted in a $114 million gain ($111 million after income taxes, or $0.25 per diluted share).

The third quarter of 2008 includes an $83 million gain ($101 million after income taxes, or $0.23 per diluted share) as a result of completing the sale of Devon s assets in Cote d Ivoire.

The fourth quarter of 2008 includes reductions of the carrying values of oil and gas properties totaling $494 million ($465 million after income taxes, or $1.05 per diluted share).

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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, 2009 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 18, 2010, management concluded that its internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of Devon s internal control over financial reporting as of December 31, 2009 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, 2009, as stated in their report, which is included under Item 8. Financial Statements and Supplementary Data.

Changes in Internal Control Over Financial Reporting

There was no change in Devon s internal control over financial reporting during the fourth quarter of 2009 that has materially affected, or is reasonably likely to materially affect, Devon s internal control over financial reporting.

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

Not applicable.

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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, 2010.

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, 2010.

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, 2010.

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, 2010.

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, 2010.

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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
1.1	Underwriting Agreement, dated as of January 6, 2009, among Devon Energy Corporation and Banc of America Securities LLC, J.P. Morgan Securities Inc. and UBS Securities LLC, as representatives of the several Underwriters named therein (incorporated by reference to Exhibit 1.1 to Registrant s Form 8-K filed on January 9, 2009).
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 7, 2005).
3.2	

	Registrant s Certificate of Amendment of Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 of Registrant s Form 10-Q filed on August 7, 2008).
3.3	Registrant s Bylaws (incorporated by reference to Exhibit 3.1 of Registrant s Form 8-K filed on March 6, 2009).
4.1	Indenture, dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., 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).
4.2	Supplemental Indenture No. 1, dated as of March 25, 2002, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., 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).

Exhibit No.	Description
4.3	Supplemental Indenture No. 3, dated as of January 9, 2009, to Indenture dated as of March 1, 2002, between Registrant and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 5.625% Senior Notes due 2014 and the 6.30% Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to Registrant s Form 8-K filed on January 9, 2009).
4.4	Indenture dated as of October 3, 2001, by and among Devon Financing Corporation, U.L.C. as Issuer, Registrant as Guarantor, and The Bank of New York Mellon Trust Company, N.A., originally 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).
4.5	Senior Indenture dated as of September 28, 2001 among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., 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).
4.6	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 Mellon Trust Company, N.A., as Trustee, relating to 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).
4.7	Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to 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)).
4.8	First Supplemental Indenture, dated March 30, 1999 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to 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).
4.9	Second Supplemental Indenture, dated as of May 9, 2001 to Indenture dated as of July 8, 1998 among Devon OEI Operating, Inc. (as successor by merger to 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).
4.10	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, N.A., 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).
4.11	Senior Indenture dated September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The Bank of New York Mellon Trust Company, N.A., 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)).
4.12	First Supplemental Indenture, dated as of March 30, 1999 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.) and The

Bank of New York Mellon Trust Company, N.A., 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).

Exhibit No.	Description
4.13	Second Supplemental Indenture, dated as of May 9, 2001 to Senior Indenture dated as of September 1, 1997, among Devon OEI Operating, Inc. (as successor by merger to Ocean Energy, Inc.), its Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., 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).
4.14	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 Mellon 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 (incorporated by reference to Annex C to the Joint Proxy Statement/Prospectus of Form S-4 Registration Statement No. 333-68694 as filed August 30, 2001).
10.2	First Amendment to Credit Agreement dated as of December 19, 2007, among Registrant as Borrower, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.3 to Registrant s Form 10-K filed February 27, 2009).
10.3	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).
10.4	First Amendment to Amended and Restated Credit Agreement dated as of June 1, 2006, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment. (incorporated by reference to Exhibit 10.2 to Registrant s Form 10-Q filed on November 7, 2007).
10.5	Second Amendment to Amended and Restated Credit Agreement dated as of September 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party to this Amendment. (incorporated by reference to Exhibit 10.3 to Registrant s Form 10-Q filed on November 7, 2007).
10.6	Third Amendment to Amended and Restated Credit Agreement dated as of December 19, 2007, among Registrant as the US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.7 to Registrant s Form 10-K filed February 27, 2009).
10.7	Fourth Amendment to Amended and Restated Credit Agreement dated as of April 7, 2008, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent and the Lenders party thereto (incorporated by reference to Exhibit 10.1 of Registrant s Form 10-Q filed on May 7, 2008).
10.8	

Fifth Amendment to Amended and Restated Credit Agreement dated as of November 5, 2008, among Registrant as US Borrower, Northstar Energy Corporation and Devon Canada Corporation as the Canadian Borrowers, Bank of America, N.A., individually and as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.2 of Registrant s Form 10-Q filed on November 6, 2008).

Exhibit No.	Description
10.9	364-Day Credit Agreement dated as of November 3, 2009 among Registrant as Borrower, Bank of America, N.A. as Administrative Agent, JPMorgan Chase Bank, N.A. as Syndication Agent, and The Other Lenders party thereto, Banc of America Securities LLC and J.P. Morgan Securities, Inc. as Joint Lead Arrangers and Book Managers for the $700 Million Short-Term Credit Facility (incorporated by reference to Exhibit 10.1 of Registrant s Form 10-Q filed on November 5, 2009).
10.10	Devon Energy Corporation 2009 Long-Term Incentive Plan (incorporated by reference to Registrant s Form S-8 Registration No. 333-159796, filed June 5, 2009).*
10.11	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).*
10.12	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).*
10.13	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).*
10.14	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).*
10.15	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).*
10.16	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).*
10.17	Amended and Restated Form of Employment Agreement between Registrant and David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt dated December 15, 2008 (incorporated by reference to Exhibit 10.19 to Registrant s Form 10-K filed February 27, 2009).*
10.18	Form of Employee Nonqualified Stock Option Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for nonqualified stock options granted.*
10.19	Form of Incentive Stock Option Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for incentive stock options granted.*
10.20	Form of Non-Management Director Nonqualified Stock Option Award Agreement under the Devon Energy Corporation 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for nonqualified stock options granted.*
10.21	Form of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and David A. Hager, R. Alan Marcum, J. Larry Nichols, John Richels, Frank W. Rudolph, Darryl G. Smette, Lyndon C. Taylor and William F. Whitsitt for restricted stock awards.*
10.22	Form of Restricted Stock Award Agreement under the 2009 Long-Term Incentive Plan between Registrant and all Non-Management Directors for restricted stock awards.*
10.23	Amended and Restated Severance Agreement between Registrant and Danny J. Heatly, dated December 15, 2008 (incorporated by reference to Exhibit 10.27 to Registrant s Form 10-K filed on February 27, 2009).*

	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.

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Exhibit No.	Description
23.4	Consent of AJM Petroleum Consultants.
31.1	Certification of principal executive office pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of principal financial officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of principal executive officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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99.1	Report of LaRoche Petroleum Consultants.
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101.INS	XBRL Instance Document
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101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
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* Compensatory plans or arrangements

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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 24, 2010

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 24, 2010
/s/ John Richels John Richels	President and Director	February 24, 2010
/s/ Danny J. Heatly Danny J. Heatly	Senior Vice President Accounting and Chief Accounting Officer	February 24, 2010
/s/ Thomas F. Ferguson Thomas F. Ferguson	Director	February 24, 2010
/s/ John A. Hill John A. Hill	Director	February 24, 2010
/s/ Robert L. Howard Robert L. Howard	Director	February 24, 2010
/s/ Michael M. Kanovsky Michael M. Kanovsky	Director	February 24, 2010
/s/ J. Todd Mitchell	Director	February 24, 2010

J. Todd Mitchell		
/s/ Robert A. Mosbacher, Jr.	Director	February 24, 2010
Robert A. Mosbacher, Jr.		
/s/ Mary P. Ricciardello	Director	February 24, 2010
Mary P. Ricciardello		

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