Gretchen Kohler, lead environmental specialist for Williams' operations in Wyoming's Powder River Basin

2009 Annual Report

The Williams Companies, Inc.

Ingenuity takes energy.®

Williams®

Financial Highlights

Dollars in millions, except per-share amounts

	2009	2008	2007	2006	2005
Revenues[1]	**$8,255**	$11,890	$ 10,239	$ 9,144	$ 9,537
Income from continuing operations[2]	**584**	1,467	910	366	458
Income (loss) from discontinued operations[3]	**(223)**	125	170	(17)	(116)
Cumulative effect of change in accounting principle[4]	**—**	—	—	—	(2)
Amounts attributable to The Williams Companies, Inc.:					
Income from continuing operations	**438**	1,306	829	332	446
Income (loss) from discontinued operations	**(153)**	112	161	(23)	(130)
Cumulative effect of change in accounting principle	**—**	—	—	—	(2)
Diluted earnings (loss) per common share:					
Income from continuing operations	**.75**	2.21	1.37	.55	.75
Income (loss) from discontinued operations	**(.26)**	.19	.26	(.04)	(.22)
Total assets at December 31	**25,280**	26,006	25,061	25,402	29,443
Short-term notes payable and long-term debt due within one year at December 31	**17**	18	108	358	88
Long-term debt at December 31	**8,259**	7,683	7,580	7,410	7,344
Stockholders' equity at December 31	**8,447**	8,440	6,375	6,073	5,427
Cash dividends declared per common share	**.44**	.43	.39	.345	.25

[1] Amounts for 2008 and 2007 have been adjusted to reflect the presentation of certain revenues and costs for Midstream on a net basis. These adjustments reduced previously reported *revenues* and *costs and operating expenses* by the same amounts, with no impact to segment profit. The reductions were $295 million in 2008 and $99 million in 2007.

[2] See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales, impairments, and other accruals in 2009, 2008, and 2007. Income from continuing operations for 2006 includes a $73 million charge for a litigation contingency. Income from continuing operations for 2005 includes an $82 million charge for litigation contingencies and a $110 million charge for impairments of certain equity investments.

[3] See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2009, 2008, and 2007 income (loss) from discontinued operations. The discontinued operations results for 2006 includes our former power business, discontinued Venezuela operations, as well as amounts associated with our former chemical fertilizer business, a former exploration business, our former Alaska refinery, and our former distributive power business. The discontinued operations results for 2005 include our former power business and discontinued Venezuela operations.

[4] The 2005 *cumulative effect of change in accounting principle* is due to the implementation of Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB statement No. 143 (SFAS No. 143)."

On the cover: *Environmental specialist Gretchen Kohler, and other Williams employees, combine responsible energy development and community involvement in their work with Wyoming and Colorado school children. Each year they participate in programs, like World Water Monitoring Day, that help teach local kids the importance of water quality and how to become good environmental stewards.*

Forward-Looking Statements: *Certain matters discussed in this report, except historical information, include forward-looking statements. Although Williams believes such statements are based on reasonable assumptions, no assurance can be given that every objective will be achieved. For more detail, see page 22 of the Form 10-K in the back of this report.*

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Fellow shareholders,

Let me begin by saying that I'm very pleased with the company's performance in what we knew was going to be a very difficult year. As 2009 began, we were in the midst of the most significant economic recession in a generation. As a result of the broad economic slowdown, energy commodity prices were driven dramatically lower across the board. In some cases, energy prices fell as much as 70-80 percent from their high points in mid-2008.

Steve Malcolm
Chairman, President and Chief Executive Officer

Much lower natural gas and natural gas liquid (NGL) prices were the primary reason that our 2009 financial results were unfavorable compared with 2008. I believe our performance in such a difficult environment reflects very well on our talented work force and high-quality natural gas businesses.

In last year's annual shareholder letter, I told you that Williams was well-positioned to ride out the economic storm because of our financial strength, world-class natural gas assets and disciplined approach to growth. At that time, I outlined our 2009 priorities, which included maintaining a solid balance sheet and ample liquidity, driving down costs, completing key infrastructure projects and seizing the right growth opportunities. Leveraging our financial strength and disciplined approach, I'm happy to report that we delivered on these priorities across the board:

> Our balance sheet and liquidity remained strong throughout the year. As expected, we retained our investment-grade credit ratings and ended the year with more than $3.7 billion in total liquidity.

> We significantly reduced our capital expenditures for the year, which were more than $1.0 billion below the 2008 level.

> We also aggressively managed our operating costs, which were lower even before the direct and indirect impact of lower natural gas prices.

> We completed and placed into service a number of key infrastructure projects, including:
- The new Willow Creek natural gas processing plant in the Piceance Basin, which will boost the volume of NGLs we recover in the basin by up to 30,000 barrels per day
- Phase II of the Sentinel expansion on the Transco interstate gas pipeline system, which increases firm transportation capacity into the northeastern United States by 102,000 dekatherms per day
- The Colorado Hub Connection, a pipeline and related facilities that connect a regional hub in the Piceance Basin to the Northwest Pipeline system

> We also seized some key growth opportunities, including:
- Entering the prolific Marcellus Shale via joint ventures in both our midstream and exploration and production businesses (more on this later)
- Adding to our significant acreage position in the Piceance Basin with an acquisition that is estimated to provide 795 billion cubic feet equivalent (Bcfe) of net proved, probable, and possible reserves

As economic conditions and commodity prices improved throughout 2009, so did our business performance. The market rewarded our improving performance, outlook and financial strength in what was a tough climate. Williams' total return to our shareholders during 2009 was 49.8 percent.

Looking Ahead – Poised for Significant Growth

We continue to believe in the importance of natural gas to our nation's energy future.

With a difficult, but ultimately successful year behind us, I see exciting prospects for Williams' growth going forward.

The Piceance Basin in western Colorado is a world-class resource where we continue to build on our presence. While we pulled back on our drilling activities in 2009, we are planning on ramping up production as the economy and prices recover. As I previously noted, we began operations at the 450 million cubic feet per day (MMcf/d) Willow Creek gas processing plant during 2009 and are reaping the benefits of increased processing capacity and NGL production. And we are already planning on expanding our processing capacity in the basin.

For Williams, the Piceance is a low-cost basin that competes very favorably with the new shale plays in North America. We benefit from our large-scale presence that spans all of our businesses and the expertise that comes from long experience in the Rockies. It will continue to be a very important area for us in the future.

The improvement of the basis differential between Henry Hub and Rockies natural gas prices has even further strengthened the value of our Piceance resource. And since this improvement has largely been driven by new permanent pipeline infrastructure, we believe the reduced basis differential will be present for the near- and long-term.

But the Piceance is not the only area where we are expanding. Significant midstream expansions in the deepwater Gulf of Mexico and Rockies are currently under way. For example, we expect to start up the Perdido Norte project in the western deepwater Gulf of Mexico during the first half of this year. This project expands our existing infrastructure and includes a total of 184 miles of deepwater oil and gas pipeline and a 200 MMcf/d expansion of our onshore Markham gas processing facility. We also will complete the TXP4 expansion at our Echo Springs processing plant in Wyoming this year. The new processing train will nearly double the plant's processing and NGL production capacity.

We also have a significant number of expansion projects on both the Transco and Northwest Pipeline systems that we expect to place into service over the next few years. These projects will increase delivery capacity to key markets in the South, Mid-Atlantic, Northeast and Pacific Northwest.

There's no question that there are ample opportunities for expansion and growth across our existing businesses. I've often described our natural gas businesses as "opportunity rich" and that is certainly the case.

Financial Restructuring to Enable More Growth

A key initiative that will help us take advantage of more of these growth projects was the $12 billion strategic restructuring we completed earlier this year.

As you know, we contributed most of our interstate gas pipeline and midstream assets to Williams Partners L.P. (NYSE: WPZ), the master limited partnership (MLP) we formed in 2005. In exchange for these assets, Williams received a significantly increased ownership interest in Williams Partners.

This transaction transformed Williams Partners from a medium-sized MLP focused on midstream operations to a large, diverse MLP with significant interstate gas pipeline and midstream assets. In fact, Williams Partners is now the third largest energy MLP in the country and also now has investment-grade credit ratings.

There is a lot of detailed information on our Web site about the restructuring that you can read for more information. But the key takeaways are that it will lower capital costs and provide Williams Partners, which will now fund Midstream and Gas Pipeline growth, with more consistent access to debt and equity markets. This means more opportunities to invest in growth projects across all of our businesses today and in the future. Also, the growth in Williams Partners' earnings and cash flows will drive similar results at Williams.

Bright Future for Natural Gas

We continue to believe in the importance of natural gas to our nation's energy future. Responsible natural gas development will reduce the country's demand for foreign energy sources, curb carbon emissions, and make renewable energy sources, such as wind and solar, viable options in the future.

Through our membership in America's Natural Gas Alliance (ANGA), we are working very hard to educate lawmakers and the public on the benefits of natural gas and its importance to our collective future. I'm on the executive committee of ANGA and have personally met with several key lawmakers over the past year to help educate them on the benefits of natural gas as an abundant, job-creating, domestic, cleaner-burning energy source.

Highlighted by the new unconventional shale plays such as the Marcellus Shale in the Northeast, there is more than a 100-year supply of natural gas in the United States. This amount continues to expand because of the use of new technologies.

As these new shale plays develop, there will be a need for new natural gas infrastructure – assets that can gather, process and transport the gas to new and existing markets across the country. There will be an enormous number of investment opportunities. Williams' long experience in operating world-class natural gas infrastructure assets ideally positions us to pursue the opportunities in these new plays where they make sense.

There's no question that there are ample opportunities for expansion and growth across our existing businesses.

One of the keys of responsible development is continual improvement of social, environmental and governance standards and practices.

An example of these new opportunities is our growing presence in the Marcellus Shale. While our Transco pipeline has traversed the heart of the basin for years, our midstream business entered this prolific shale play during 2009 via the Laurel Mountain Midstream joint venture. Almost from the moment we established our offices in Pennsylvania, we began getting feedback from producers who were thrilled that a company with Williams' expertise in operating large-scale gathering systems was entering the Marcellus. Earlier this year, we signed a long-term gathering agreement with Cabot Oil & Gas, which will lead to us building a new gathering pipeline in north Pennsylvania.

Given its strategic position, the Transco system will play a key role in opening attractive markets for delivery of the Marcellus gas to key markets, including New York City and the growing Southeast. There are already a number of expansion projects under way.

In addition to our growing midstream and gas pipeline presence, our exploration and production business also entered the Marcellus Shale during 2009 via a joint venture with Rex Energy. We've already begun drilling operations on the 44,000 net acres that are part of the joint venture. We expect that we will continue to grow our presence in this important area in 2010 and beyond.

As always, we will approach any new investments with strict financial discipline and a sharp focus on long-term value growth.

The Importance of Responsible Development

Williams has long been known as a responsible developer of our nation's natural gas resources. We've always believed that it's our great responsibility to produce, process and transport this vital energy source in a way that is safe and environmentally sound.

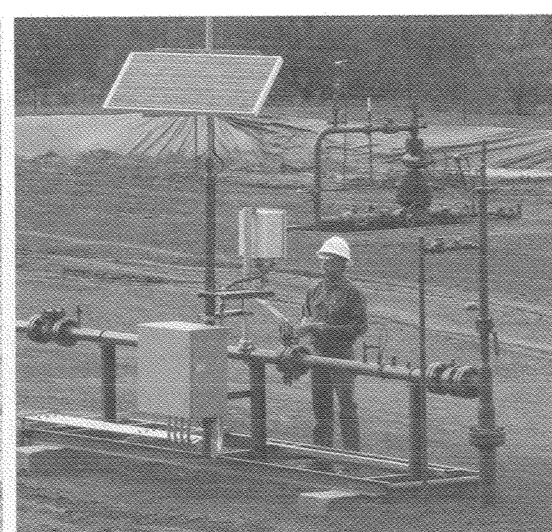
One of the keys of responsible development is continual improvement of social, environmental and governance standards and practices. Williams was once again recognized for these efforts during 2009:

> We were recognized with two awards for Operational Excellence by the Colorado Oil and Gas Conservation Commission: reclamation for mitigating the visibility of operations and for reducing noxious weeds

> Our exploration and production and gas pipeline businesses received Continuing Excellence Awards for five and 15 years, respectively, of participation in the U.S. EPA Natural Gas STAR program

> The company adopted the model code of conduct on corporate political spending and accountability developed by the Center for Political Accountability.

Responsible development is not only the right thing to do, but it's also going to be vitally important



in the future as natural gas development moves into areas of the country that haven't experienced development before. The companies that are known for transparency, community partnerships and responsible development will be in a better position as we help grow our nation's energy infrastructure.

I also would like to recognize the hard work of Williams' 4,800 employees. More than half of our employees are also Williams shareholders. So to those employees reading this letter, I thank you for your continued contributions to our success.

We put a lot of effort into attracting and retaining a high-quality work force, and we're proud that these efforts were recognized in some of our key areas of operation during 2009:

> The *Houston Business Journal* named Williams as the #1 Best Place to Work in Houston among the companies not based in Houston. This was the second year in a row Williams was recognized on the Best Place to Work in Houston list, and the first time we won the top spot.

> *Utah Business* magazine named Williams as a finalist in its Best Companies to Work For program, where we were recognized as one of the four best medium-sized companies in Utah.

> *OKCBiz* magazine recognized Williams on its Best Places to Work in Oklahoma list for the second year in a row.

Final Thoughts

Most data points to an ongoing economic recovery and resulting strengthening of natural gas and NGL prices in 2010-11. Our outlook for profitability and capital expenditures reflects this improvement in the overall economy. However, many challenges remain that we are watching very closely.

The long and involved debate on health care legislation in Washington, D.C., has somewhat delayed the momentum on new climate legislation, but we expect something may be enacted this year or next. As I previously mentioned, we're working very hard through ANGA to ensure that benefits of natural gas are represented in the final bill, but until we know what it looks like, some uncertainty will remain about its ultimate impact on natural gas companies like Williams.

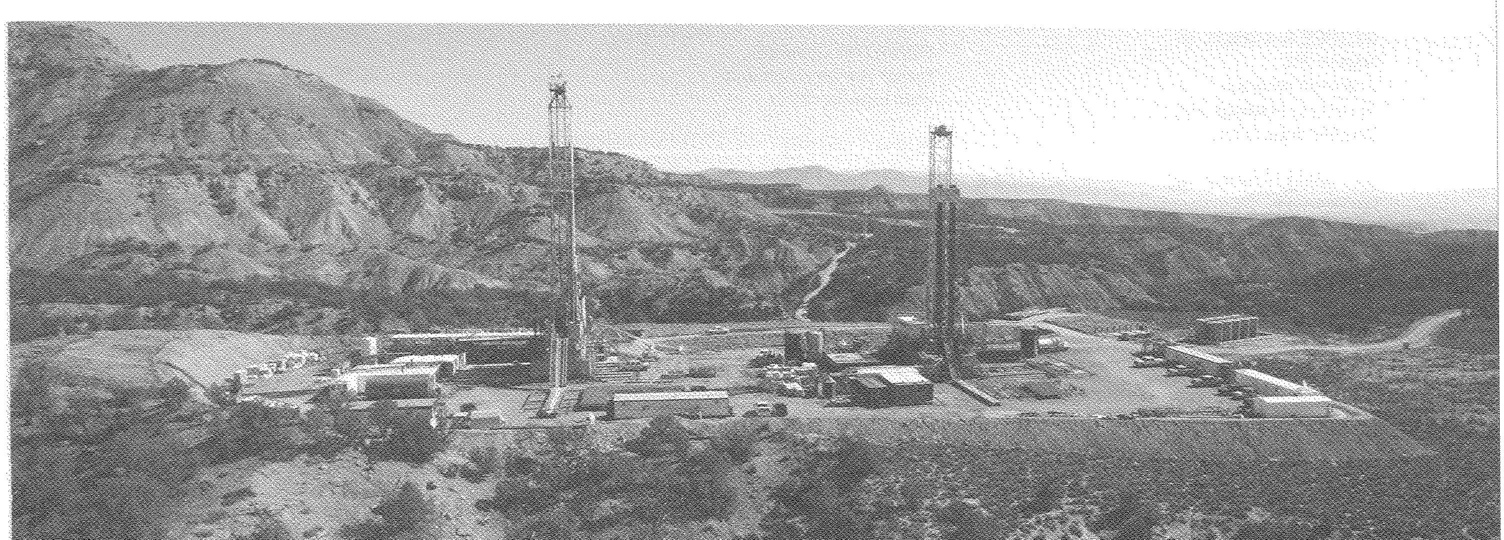
What I do know is that Williams is well-positioned to be successful in a wide variety of commodity price, economic and regulatory environments. We've proven that over and over again. We have world-class natural gas assets, a solid strategy, a deep and talented work force and the opportunities to continue our tradition of disciplined growth and value creation.

Thank you for your continued support.

Steve Malcolm

STEVE MALCOLM
Chairman, President and Chief Executive Officer
March 30, 2010

As always, we will approach any new investments with strict financial discipline and a sharp focus on long-term value growth.



Directors and Officers

DIRECTORS

STEVEN J. MALCOLM, 61
Tulsa, Okla.
Chairman, president and chief executive officer, Williams.
Director since 2001.

JOSEPH R. CLEVELAND, 65
Orlando, Fla.
Former chief information officer, Lockheed Martin Corporation.
Director since 2008.

KATHLEEN B. COOPER, 65
Dallas, Texas
Senior fellow, Tower Center for Political Studies, Southern Methodist University.
Director since 2006.

IRL F. ENGELHARDT, 63
St. Louis, Mo.
Chairman, Patriot Coal Corporation.
Director since 2005.

WILLIAM R. GRANBERRY, 67
Midland, Texas
Member, Compass Operating Company LLC.
Director since 2005.

WILLIAM E. GREEN, 73
Palo Alto, Calif.
Founder, William Green & Associates.
Director since 1998.

JUANITA H. HINSHAW, 65
St. Louis, Mo.
President and chief executive officer, H&H Advisors.
Director since 2004.

W. R. HOWELL, 74
Wilson, Wyo.
Chairman emeritus, J.C. Penney Company, Inc.
Director since 1997.

GEORGE A. LORCH, 68
Naples, Fla.
Chairman emeritus, Armstrong Holdings, Inc.
Director since 2001.

WILLIAM G. LOWRIE, 66
Sheldon, S.C.
Former deputy chief executive officer, BP Amoco PLC.
Director since 2003.

FRANK T. MACINNIS, 63
Norwalk, Conn.
Chairman of the board and chief executive officer, EMCOR Group Inc.
Director since 1998.

JANICE D. STONEY, 69
Omaha, Neb.
Former executive vice president, U S WEST Communications Group, Inc.
Director since 1999.

HONORARY DIRECTORS

JOHN H. WILLIAMS, 91
Tulsa, Okla.
Co-founder of Williams Brothers Company in 1949. President and chief executive officer for Williams from 1949-79; chairman and chief executive officer from 1971-79.
Elected to the board in 1949.

JOSEPH H. WILLIAMS, 76
Tulsa, Okla.
Chairman and chief executive officer for Williams from 1979-1994.
Elected to the board in 1969.

SENIOR OFFICERS

STEVEN J. MALCOLM
Chairman, president and chief executive officer

ALAN S. ARMSTRONG
Senior vice president, Midstream Gathering & Processing

JAMES J. BENDER
Senior vice president and general counsel

DONALD R. CHAPPEL
Senior vice president and chief financial officer

ROBYN L. EWING
Senior vice president and chief administrative officer

RALPH A. HILL
Senior vice president, Exploration & Production

PHILLIP D. WRIGHT
Senior vice president, Gas Pipeline

BOARD COMMITTEES

Audit Committee

Joseph R. Cleveland
Irl F. Engelhardt
William E. Green
Juanita H. Hinshaw
William G. Lowrie (Chair)

Compensation Committee

Kathleen B. Cooper
William R. Granberry
W. R. Howell (Chair)
George A. Lorch
Frank T. MacInnis
Janice D. Stoney

Finance Committee

Joseph R. Cleveland
Kathleen B. Cooper
Irl F. Engelhardt
William R. Granberry
Juanita H. Hinshaw (Chair)

Nominating & Governance Committee

William E. Green
W. R. Howell
George A. Lorch
William G. Lowrie
Frank T. MacInnis (Chair)
Janice D. Stoney

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **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

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-4174

The Williams Companies, Inc.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**73-0569878**
(State or Other Jurisdiction of Incorporation or Organization)	*(IRS Employer Identification No.)*
One Williams Center, Tulsa, Oklahoma	**74172**
(Address of Principal Executive Offices)	*(Zip Code)*

918-573-2000

(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1.00 par value	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

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

5.50% Junior Subordinated Convertible Debentures due 2033

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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 ☐ No ☑

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 ☑ No ☐

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 ☑ No ☐

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

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 ☑ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant's most recently completed second quarter was approximately $9,096,736,726.

The number of shares outstanding of the registrant's common stock outstanding at February 19, 2010 was 583,598,142.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Definitive Proxy Statement for the Registrant's 2010 Annual Meeting of Stockholders to be held on May 20, 2010, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.
FORM 10-K

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DEFINITIONS

We use the following oil and gas measurements in this report:

Bcfe — means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Bcf/d — means one billion cubic feet per day.

British Thermal Unit or BTU — means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

BBtud — means one billion BTUs per day.

Dekatherms or Dth or Dt — means a unit of energy equal to one million BTUs.

Mbbls/d — means one thousand barrels per day.

Mcfe — means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

Mdt/d — means one thousand dekatherms per day.

MMcf — means one million cubic feet.

MMcf/d — means one million cubic feet per day.

MMcfe — means one million cubic feet of gas equivalent using the ratio of one barrel of oil or condensate to six thousand cubic feet of natural gas.

MMdt — means one million dekatherms or approximately one trillion BTUs.

MMdt/d — means one million dekatherms per day.

TBtu — means one trillion BTUs.

PART I

Item 1. *Business*

In this report, Williams (which includes The Williams Companies, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as "we," "us" or "our." We also sometimes refer to Williams as the "Company."

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents electronically with the Securities and Exchange Commission (SEC) under the Securities Exchange Act of 1934, as amended (Exchange Act). You may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. You may also obtain such reports from the SEC's Internet website at *http://www.sec.gov.*

Our Internet website is *http://www.williams.com.* We make available free of charge on or through our Internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Our Corporate Governance Guidelines, Code of Ethics, Board Committee Charters and Code of Business Conduct are also available on our Internet website. We will also provide, free of charge, a copy of any of our corporate documents listed above upon written request to our Corporate Secretary, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172.

GENERAL

We are a natural gas company originally incorporated under the laws of the state of Nevada in 1949 and reincorporated under the laws of the state of Delaware in 1987. We were founded in 1908 when two Williams brothers began a construction company in Fort Smith, Arkansas. Today, we primarily find, produce, gather, process and transport natural gas. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Eastern Seaboard, and the province of Alberta in Canada.

Our principal executive offices are located at One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 918-573-2000.

In 2009, we used Economic Value Added® (EVA®)[1] as the basis for disciplined decision making around the use of capital. EVA® is a tool that considers both financial earnings and a cost of capital in measuring performance. It is based on the idea that earning profits from an economic perspective requires that a company cover not only all of its operating expenses but also all of its capital costs. The two main components of EVA® are net operating profit after taxes and a charge for the opportunity cost of capital. We derive these amounts by making various adjustments to our reported results and financial position, and by applying a cost of capital. We look for opportunities to improve EVA® because we believe there is a strong correlation between EVA® improvement and creation of shareholder value.

STRATEGIC RESTRUCTURING

On February 17, 2010, we completed a strategic restructuring, which involved contributing a substantial majority of our domestic midstream and gas pipeline businesses, including our limited- and general-partner interests in Williams Pipeline Partners L.P. (WMZ), into Williams Partners L.P. (WPZ). As consideration for the asset contributions, we received proceeds from WPZ's debt issuance of approximately $3.5 billion, less WPZ's transaction fees and expenses, as well as 203 million WPZ Class C units, which are identical to common units, except for a prorated initial distribution. We also maintained our 2 percent general-partner interest. WPZ assumed

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[1] Economic Value Added® (EVA®) is a registered trademark of Stern, Stewart & Co.

approximately $2 billion of existing debt associated with the gas pipeline assets. In connection with the restructuring, we retired $3 billion of our debt and paid $574 million in related premiums. These amounts, as well as other transaction costs, were primarily funded with the cash consideration received from WPZ. As a result of our restructuring, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions. (See Note 19 of Notes to Consolidated Financial Statements.)

In conjunction with the restructuring, WPZ has announced its intention to launch an exchange offer for the publicly traded common units of WMZ at a future date. WPZ will offer a fixed exchange ratio of 0.7584 of its common units for each WMZ common unit. The ratio is based on closing prices on the New York Stock Exchange on Friday, January 15, 2010, the business day before WPZ's intention to make the exchange offer was announced, of $23.35 for WMZ and $30.79 for WPZ. The exact timing of the launch will be based upon the filing of necessary offering documents with the SEC and upon market conditions. If WPZ acquires ownership of more than 75% of WMZ's outstanding common units pursuant to this offer, WPZ will consider causing the general partner of WMZ to (i) deregister WMZ under the Exchange Act or cause its common units to no longer be traded on the New York Stock Exchange, if these options are available, (ii) exercise its right under the WMZ's limited partnership agreement to purchase all of the remaining common units or (iii) exercise any other available options.

Beginning with reporting of first-quarter 2010 results, we will change our segment reporting structure to align with the new parent-level focus, resource allocation management and related governance provisions resulting from the restructuring. Our reporting segments will be Williams Partners, Exploration & Production, and Other. Exploration & Production will include our current Gas Marketing Services (Gas Marketing) segment and Other will include certain midstream and gas pipeline businesses that were not contributed to WPZ, such as our Canadian and olefins midstream businesses and the remaining 25.5 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream), as well as corporate operations.

Information in this report has generally been prepared to be consistent with the reportable segment presentation in our consolidated financial statements in Part II, Item 8 of this document, which reflects our segment reporting structure prior to the restructuring. These segments are discussed in further detail in the following sections.

FINANCIAL INFORMATION ABOUT SEGMENTS

See "Item 8 — Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements — Note 18" of our Notes to Consolidated Financial Statements for information with respect to each segment's revenues, profits or losses and total assets.

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities in 2009 were primarily operated through the following business segments:

- *Exploration & Production* — produces, develops and manages natural gas reserves primarily located in the Rocky Mountain and Mid-Continent regions of the United States and is comprised of several wholly owned and partially owned subsidiaries including Williams Production Company, LLC, and Williams Production RMT Company (RMT).
- *Gas Pipeline* — includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC (WGP). Gas Pipeline also includes Williams Pipeline Partners L.P. (WMZ), our master limited partnership formed in 2007.
- *Midstream Gas & Liquids* — includes our natural gas gathering, treating and processing business and is comprised of several wholly owned and partially owned subsidiaries including Williams Field Services Group, LLC and Williams Natural Gas Liquids, Inc. Midstream Gas & Liquids (Midstream) also includes Williams Partners L.P. (WPZ), our master limited partnership formed in 2005.

- *Gas Marketing Services* — manages our natural gas commodity risk through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Gas Marketing, Inc.
- *Other* — primarily consists of corporate operations.

This report is organized to reflect this structure.

Detailed discussion of each of our business segments follows.

Exploration & Production

Our Exploration & Production segment produces, develops, and manages natural gas reserves primarily located in the Rocky Mountain (primarily Colorado, New Mexico, and Wyoming), Mid-Continent (Oklahoma and Texas), and Appalachian regions of the United States. We specialize in natural gas production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Arkoma, Green River, Fort Worth, and Appalachian basins. Over 99 percent of our domestic reserves are natural gas. We also have international oil and gas interests, which include a 69 percent equity interest in Apco Oil and Gas International Inc. (formerly Apco Argentina Inc., NASDAQ listed: APAGF), an oil and gas exploration and production company with operations in South America. If combined with our domestic proved reserves, our international interests would make up approximately 4 percent of our total proved reserves. Considering this, the reserves information included in this section relates only to our domestic activity.

Our goal is to continue to drill our existing proved undeveloped reserves, which comprise approximately 44 percent of proved reserves, and to drill in areas of probable and possible reserves in order to add to our proved reserves. Our current proved, probable, and possible reserves inventory provides us with strong capital investment opportunities for many years into the future.

On January 14, 2009, the SEC issued the *Final Rule for Modernization of Oil and Gas Reporting* which modifies how oil and gas companies report reserves estimates. We have adopted the revised SEC oil and gas reporting requirements, effective as of December 31, 2009, with the following effects:

- Applying the expanded definition of oil and gas reserves used for reserves estimation supported by reliable technologies and reasonable certainty.
- Choosing to disclose two alternative reserves sensitivity scenarios.
- Revising proved undeveloped reserves estimates based on new guidance.
- Estimating reserves for SEC disclosure using the 12-month average, first-of-the-month price instead of a single-day, period-end price.
- Incorporating certain additional disclosures around proved undeveloped reserves, internal controls used to ensure objectivity of the estimation process, and qualifications of those preparing and/or auditing the reserves.

Oil and Gas Reserves

Reserves information is reported as gas equivalents, since oil volumes are insignificant. Reserves are more than 99 percent natural gas for all periods indicated.

Summary of oil and gas reserves:

	December 31,		
	2009	2008	2007
		(Bcfe)	
Proved developed reserves	2,387	2,456	2,252
Proved undeveloped reserves	1,868	1,883	1,891
Total proved reserves	4,255	4,339	4,143

We have not filed on a recurring basis estimates of our total proved net oil and gas reserves with any U.S. regulatory authority or agency other than with the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC.

Proved reserves sensitivities price scenario

The new SEC rules allow for reserves sensitivity analysis using alternate price and cost criteria as shown below. The SEC case was derived using the 12-month average, first-of-the-month Henry Hub spot price of $3.87 per MMbtu, adjusted for locational price differentials. Neither of the sensitivity scenarios was audited by a third party. All three cases assume that proved undeveloped reserves are drilled within five years. No changes were made to capital expenditures or operating costs in the sensitivity scenarios.

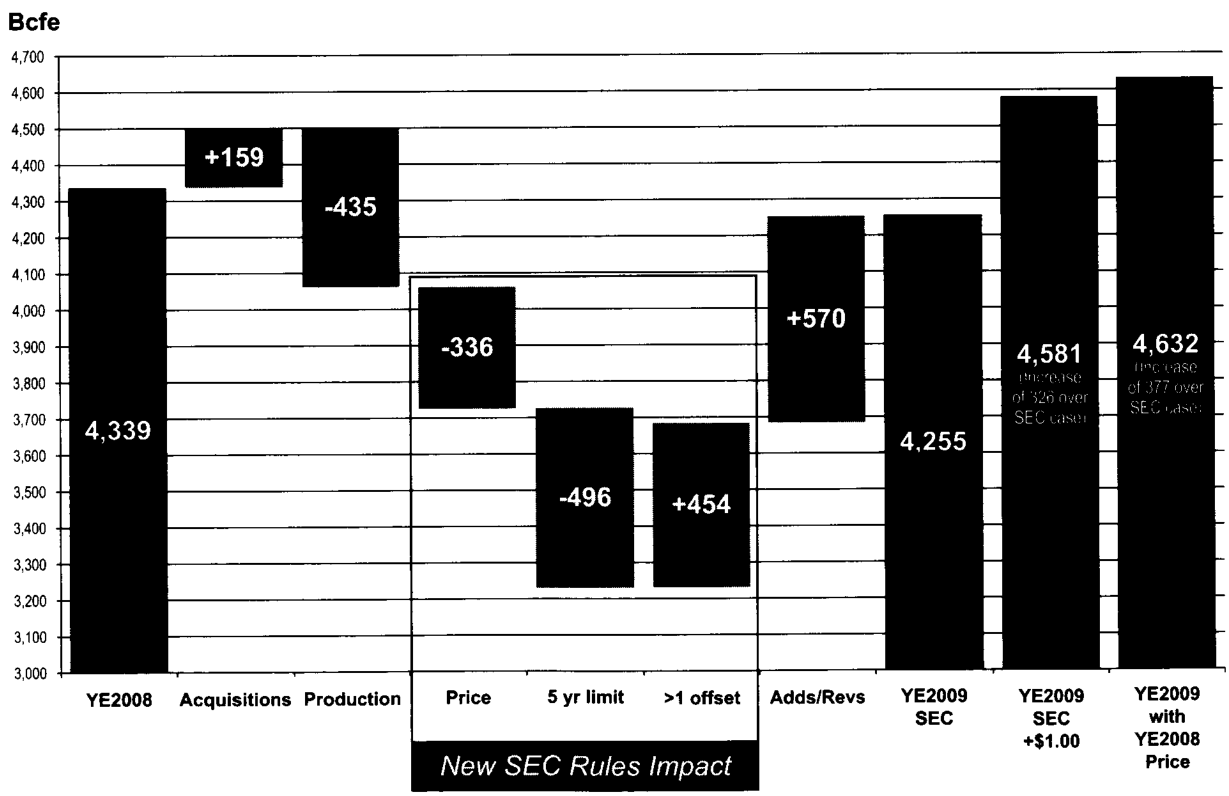
Basin	SEC Case	Sensitivity 1 (Bcfe)	Sensitivity 2
Piceance	3,207	3,430	3,455
San Juan	467	491	505
Powder River	304	349	356
Mid-Continent	210	228	231
Other	67	83	85
Total	4,255	4,581	4,632

Sensitivity 1: Reflects proved reserves estimated by adding $1.00 to each of the basin prices from the SEC case.

Sensitivity 2: Reflects proved reserves estimated using prices from the prior year-end, which were calculated using the December 31, 2008, NYMEX Henry Hub posted price of $5.71 per MMbtu, adjusted for locational price differentials.

The chart below shows the year-end 2009 SEC case compared to the two alternate price scenarios. Also shown is the impact the new SEC reserves rules had on 2009 proved reserves.

Proved U.S. Reserves Reconciliation



The new SEC reporting rules require that year-end proved reserve volumes are calculated using an average price for the full-year 2009, rather than the year-end price. This resulted in utilization of a basin price approximately 33 percent lower than the previous year which resulted in a downward price revision of 336 Bcfe.

Under the new rules, reserves generally cannot be classified as proved if they have not or will not be developed within five years according to planned drilling activity and taking into account anticipated proved undeveloped conversion rates for wells drilled. This rule change resulted in reclassification of 496 Bcfe of reserves from proved undeveloped to probable.

Additionally, the new rules now allow adding undeveloped proved reserves locations that are more than one offset away from currently producing wells where there is reasonable certainty of production. This rule change resulted in the addition of 454 Bcfe of proved reserves.

Also shown on the chart is 570 Bcfe of net additions/revisions to our proved reserves through drilling 882 gross wells in 2009 at a capital cost of approximately $878 million.

Reserves estimation process

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate. These departments provide supporting information such as pricing, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our reserves analysis department. The reserves analysis department's responsibilities also include: working with the third-party consultants and the asset teams to successfully complete the third-party reserves audit, performing an internal review of reserves data for reasonableness and accuracy, finalizing the year-end reserves report, and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. We begin with a review of the existing process to identify where improvements can be made. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated. Each asset teams' reserves engineering and geological technical staffs, the reserves analysis team, and the third-party engineering consultants meet to begin the year-end process and audit. The asset teams' reserves staff, the reserves analysis team and the third-party engineering consultants exchange data and interpretations in furtherance of the completion of the year-end reserves estimates. The reserves analysis team met twice with the Audit Committee of our Board of Directors to report on the progress of its analysis of our 2009 reserves, allowing the Audit Committee the opportunity to review and comment on management's processes and conclusions.

Approximately 99 percent of our total year-end 2009 domestic proved reserves estimates were audited by Netherland, Sewell & Associates, Inc. (NSAI). When compared on a well-by-well basis, some of our estimates are greater and some are less than the estimates of NSAI. However, in the opinion of NSAI, the estimates of our proved reserves are in the aggregate reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles. These principles are set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2009, reserves estimates and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. The report of NSAI is included as Exhibit 99.1 to this Form 10-K.

In addition, reserves estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust, of which our ownership in the Trust represents approximately 1 percent of our total domestic proved reserves estimates, were prepared by Miller and Lents, LTD. The report of Miller and Lents is included as Exhibit 99.2 to this Form 10-K.

The reserves estimates resulting from the above process are subjected to both internal and external checks and controls to promote transparency and accuracy of the year-end reserves estimates. Our internal control documentation provides further confirmation on the checks and controls. Our internal reserves analysis team is independent and does not work within an asset team or report directly to anyone on the asset teams. The compensation of our reserves analysis team is not linked to reserves additions or revisions.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third-party reserves audit is the Director of Reserves and Production Services. The Director's qualifications include 27 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in physical sciences from the University of Houston, and membership in the American Association of Petroleum Geologists, and The Society of Petroleum Engineers.

Proved undeveloped reserves

Our proved undeveloped reserves as of December 31, 2009, are 1,868 Bcfe and 1,883 Bcfe as of December 31, 2008, a net decrease of approximately 15 Bcfe. See additional discussion of proved undeveloped reserves in our sensitivity analysis.

The vast majority of our reserves is concentrated in unconventional tight gas sands, shale gas and coal bed gas reservoirs. We use available geoscience and engineering data to establish drainage areas and continuity of reservoir beyond one direct offset from a producing well, which provides additional proved undeveloped bookings in fields where the evidence supported the methodology. Inherent in the methodology was a requirement for significant well density of economically producing wells to establish those bookings with reasonable certainty. In fields where producing wells were less dense, only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification.

Oil and Gas Properties and Production, Production Prices and Production Costs

The following table summarizes our domestic sales and cost information for the years indicated:

	2009	2008	2007
		(Bcfe)(1)	
Piceance	254.6	237.7	196.9
San Juan	53.1	52.8	53.4
Powder River	88.9	83.6	61.9
Mid-Continent	29.6	21.7	16.9
Other	5.3	4.6	4.0
Total net production sold	431.5	400.4	333.1
Average production costs excluding production taxes ($/Mcfe)(2)	$ 0.60	$ 0.66	$ 0.62
Average sales price ($/Mcfe)	$ 2.79	$ 6.39	$ 4.92
Realized gain on hedging contracts ($/Mcfe)	$ 1.43	$ 0.09	$ 0.16
Net Realized Average Price ($/Mcfe)	$ 4.22	$ 6.48	$ 5.08

(1) Sales and cost information are reported in gas equivalents instead of oil equivalents since oil volumes are insignificant. Production is over 99 percent natural gas for all three years indicated.

(2) Includes lease and other operating expense and facility operating expense.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2009, 2008, and 2007.

The following table summarizes domestic drilling activity by number and type of well for the periods indicated:*

	2009		2008		2007	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Piceance	349	303	687	624	572	539
San Juan	77	39	95	37	146	50
Powder River	233	95	702	324	633	255
Mid-Continent	43	41	82	62	75	48
Other	173	8	216	3	151	3
Productive exploration	3	1	4	2	4	3
Nonproductive, including exploration	4	1	1	0	9	5
Total	882	488	1,787	1,052	1,590	903

* We use the terms "gross" to refer to all wells or acreage in which we have at least a partial working interest and "net" to refer to our ownership represented by that working interest. All of the wells drilled were natural gas wells.

In 2009, there were two gross nonproductive exploratory wells and one net nonproductive exploratory well. Total gross operated wells drilled were 472 in 2009, 1,125 in 2008, and 1,112 in 2007.

Present Activities

At December 31, 2009, we had 42 gross (14 net) wells in the process of being drilled.

Delivery Commitments

We hold a long-term obligation, through our Gas Marketing segment, to deliver on a firm basis 200,000 MMBtu/d of gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance basin. The Piceance, being our largest producing basin, holds ample reserves to fulfill this obligation without risk of nonperformance during periods of normal infrastructure and market operations. While the daily volume of gas is large and represents a significant percentage of our daily production, this transaction does not represent a material exposure.

Oil and Gas Properties, Wells, Operations, and Acreage

The table below summarizes 2009 producing wells and production by area:*

	Wells Producing (Gross)	Wells Producing (Net)	Net Production (Bcfe)
Piceance	3,496	3,202	257
San Juan	3,220	871	55
Powder River	6,025	2,722	88
Mid-Continent	671	451	29
Other	737	27	6
Total	14,149	7,273	435

* We use the terms "gross" to refer to all wells or acreage in which we have at least a partial working interest and "net" to refer to our ownership represented by that working interest. All of the wells drilled were natural gas wells. Volumes are reported in gas equivalents since any liquids produced are a by-product of the natural gas wells.

At December 31, 2009, there were 181 gross and 106 net producing wells with multiple completions.

The following table summarizes our leased acreage as of December 31, 2009:

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Piceance	129,063	99,965	180,744	119,798	309,808	219,763
San Juan	237,587	119,345	2,100	1,576	239,688	120,921
Powder River	502,455	228,582	421,378	195,422	923,833	424,004
Mid-Continent	117,314	75,940	147,403	75,481	264,716	151,421
Other	30,029	5,111	549,591	309,242	579,619	314,353
Total	1,016,448	528,943	1,301,216	701,519	2,317,664	1,230,462

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2009 we operated an average of 10.3 drilling rigs in the basin. This area has approximately 1972 undrilled proved locations in inventory. Within this basin we own and operate natural gas gathering facilities including some 300 miles of gathering lines and associated field compression. Approximately 85 percent of the gas gathered is our own equity production. The gathering system also includes 5 processing plants and associated treating facilities for a total capacity of 1.15 Bcf/d. During 2009, these plants recovered approximately 6.3 million gallons of natural gas liquids (NGLs) each month, which were marketed separately from the residue natural gas.

In addition to our own operated facilities, Midstream owns and operates a new cryogenic processing plant, Willow Creek, which currently has a capacity of 450 MMcf/d and reprocesses that amount of gas, recovering an average of 12.6 million additional gallons of NGLs per month, which were marketed separately from the residue natural gas.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado. We provide a significant amount of equity production that is gathered and/or processed by Midstream's facilities in the San Juan basin.

Powder River basin

The Powder River basin is located in northeast Wyoming. The Powder River basin includes large areas with multiple coal seam potential, targeting thick coal bed methane formations at shallow depths. We have a significant inventory of undrilled locations, providing long-term drilling opportunities.

Mid-Continent properties

The Mid-Continent properties are located in the southeastern Oklahoma portion of the Arkoma basin and the Barnett Shale in the Fort Worth basin of Texas.

Other properties

Other properties are primarily comprised of interests in the Green River basin in southwestern Wyoming and the Appalachian basin (Marcellus Shale) in Pennsylvania. Also included is exploration activity and other miscellaneous activity.

Hedging Activity

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in *Management's Discussion and Analysis of Financial Condition and Results of Operations — Exploration & Production*, included in Item 7 of this Form 10-K.

Acquisitions & Divestitures

In June 2009, we entered into an agreement that allows us to acquire, through a "drill to earn" structure, a 50 percent interest in approximately 44,000 net acres in Pennsylvania's Marcellus Shale in the Appalachian basin. This agreement requires us to fund $33 million of drilling and completion costs on behalf of our partner and $41 million of our own costs and expenses prior to the end of 2011 to earn our 50 percent interest. This growth opportunity leverages our experience in developing nonconventional natural gas reserves. Through December 2009, we have funded $14 million of the $33 million.

In September 2009, we completed the purchase of additional unproved leasehold acreage and proved properties in the Piceance basin for $253 million. In December 2009, we increased our working interest in these properties through a $22 million acquisition.

Through other transactions totaling approximately $36 million, Exploration & Production expanded its acreage position and producing properties in the Fort Worth basin (Barnett Shale), the Appalachian basin (Marcellus Shale), the Arkoma basin (Woodford Shale), as well as exploration leaseholds in the Paradox basin.

Other Information

In 1993, Exploration & Production conveyed a net profits interest in certain of its properties to the Williams Coal Seam Gas Royalty Trust ("Trust"). Substantially all of the production attributable to the properties conveyed to the Trust was from the Fruitland coal formation and constituted coal seam gas. We subsequently sold Trust units to the public in an underwritten public offering and retained 3,568,791 Trust units then representing 36.8 percent of outstanding Trust units. We have previously sold Trust units on the open market, with our last sales in June 2005. As of March 1, 2010, we expect to own 789,291 trust units. Based on certain provisions of the Trust agreement, the Trust is expected to terminate on March 1, 2010. Upon termination, the net profits interest will be placed for sale and we will receive proceeds from the sale less applicable expenses in direct proportion to the Trust units owned. This transaction is expected to have a minimal impact to our financial statements.

Gas Pipeline

We own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of gas. Gas Pipeline consists of Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline). Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 50 percent interest in Gulfstream. Gas Pipeline also includes WMZ.

Transco

Transco is an interstate natural gas transportation company that owns and operates a 10,000-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, and New Jersey to the New York City metropolitan area. The system serves customers in Texas and 11 southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, Washington, D.C., New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2009, Transco's system had a mainline delivery capacity of approximately 4.7 MMdt of natural gas per day from its production areas to its primary markets. Using its Leidy Line along with market-area storage and transportation capacity, Transco can deliver an additional 3.9 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.6 MMdt of natural gas per day. Transco's system includes 45 compressor stations, four underground storage fields, and a liquefied natural gas (LNG) storage facility. Compression facilities at sea level-rated capacity total approximately 1.5 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. One customer accounted for approximately 11 percent and another customer accounted for approximately 10 percent of Transco's total revenues in 2009. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers storage services and interruptible transportation services under short-term agreements.

Transco has natural gas storage capacity in four underground storage fields located on or near its pipeline system or market areas and operates two of these storage fields. Transco also has storage capacity in an LNG storage facility that they own and operate. The total usable gas storage capacity available to Transco and its customers in such underground storage fields and LNG storage facility and through storage service contracts is approximately 204 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, a LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

The pipeline projects listed below were completed during 2009 or are significant future pipeline projects for which we have customer commitments.

Sentinel Expansion Project

The Sentinel Expansion Project is a recently completed expansion of our existing natural gas transmission system from the Leidy Hub in Clinton County, Pennsylvania and from the Pleasant Valley interconnection with Cove Point LNG in Fairfax County, Virginia to various delivery points requested by the shippers under the project. The capital cost of the project is estimated to be up to approximately $229 million. Phase I was placed into service in December 2008. Phase II was placed into service in November 2009.

Mobile Bay South Expansion Project

The Mobile Bay South Expansion Project involves the addition of compression at Transco's Station 85 in Choctaw County, Alabama, to allow Transco to provide firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In May 2009, Transco received approval from the Federal Energy Regulatory Commission (FERC). The capital cost of the project is estimated to be approximately $37 million. Transco plans to place the project into service by May 2010.

Mobile Bay South II Expansion Project

The Mobile Bay South II Expansion Project involves the addition of compression at Transco's Station 85 in Choctaw County, Alabama, and modifications to existing facilities at Transco's Station 83 in Mobile County, Alabama, to allow Transco to provide additional firm transportation service southbound on the Mobile Bay line from Station 85 to various delivery points. In November 2009, Transco filed an application with the FERC. The capital cost of the project is estimated to be approximately $36 million. Transco plans to place the project into service by May 2011.

85 North Expansion Project

The 85 North Expansion Project involves an expansion of our existing natural gas transmission system from Station 85 in Choctaw County, Alabama, to various delivery points as far north as North Carolina. In September 2009, Transco received approval from the FERC. The capital cost of the project is estimated to be $241 million. Transco plans to place the project into service in phases, in July 2010 and May 2011.

Mid-South Expansion Project

The Mid-South Expansion Project involves an expansion of Transco's mainline from Station 85 in Choctaw County, Alabama, to markets as far downstream as North Carolina. Transco anticipates filing an application with the FERC in the fourth quarter of 2010. The capital cost of the project is estimated to be approximately $200 million. Transco plans to place the project into service in September 2012.

Mid-Atlantic Connector Project

The Mid-Atlantic Connector Project involves an expansion of Transco's mainline from an existing interconnection with East Tennessee Natural Gas in North Carolina to markets as far downstream as Maryland. Transco anticipates filing an application with the FERC in the first quarter of 2011. The capital cost of the project is estimated to be approximately $55 million. Transco plans to place the project into service in November 2012.

Rockaway Delivery Lateral Project

The Rockaway Delivery Lateral Project involves the construction of a three-mile offshore lateral to National Grid's distribution system in New York. Transco anticipates filing an application with the FERC in the third quarter of 2010. The capital cost of the project is estimated to be approximately $120 million. Transco plans to place the project into service in November 2013.

Operating statistics

The following table summarizes transportation data for the Transco system for the periods indicated:

	2009	2008	2007
		(In TBtu)	
Market-area deliveries:			
Long-haul transportation	624	753	839
Market-area transportation	1,093	969	875
Total market-area deliveries	1,717	1,722	1,714
Production-area transportation	184	188	190
Total system deliveries	1,901	1,910	1,904
Average Daily Transportation Volumes	5.2	5.2	5.2
Average Daily Firm Reserved Capacity	6.8	6.8	6.6

Transco's facilities are divided into eight rate zones. Five are located in the production area, and three are located in the market area. Long-haul transportation involves gas that Transco receives in one of the production-area zones and delivers to a market-area zone. Market-area transportation involves gas that Transco both receives and delivers within the market-area zones. Production-area transportation involves gas that Transco both receives and delivers within the production-area zones.

Northwest Pipeline

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the San Juan basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon, and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in California, Arizona, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon, and Washington directly or indirectly through interconnections with other pipelines.

Pipeline system and customers

At December 31, 2009, Northwest Pipeline's system, having long-term firm transportation agreements including peaking service of approximately 3.7 Bcf of natural gas per day, was composed of approximately 3,900 miles of mainline and lateral transmission pipelines and 41 transmission compressor stations having a combined sea level-rated capacity of approximately 473,000 horsepower.

In 2009, Northwest Pipeline served a total of 127 transportation and storage customers. Northwest Pipeline transports and stores natural gas for a broad mix of customers, including local natural gas distribution companies, municipal utilities, direct industrial users, electric power generators and natural gas marketers and producers. The two largest customers of Northwest Pipeline in 2009 accounted for approximately 22 percent and 12 percent, respectively, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline's total operating revenues in 2009. Northwest Pipeline's firm transportation and storage contracts are generally long-term contracts with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

As a part of its transportation services, Northwest Pipeline utilizes underground storage facilities in Utah and Washington enabling it to balance daily receipts and deliveries. Northwest Pipeline also owns and operates an LNG storage facility in Washington that provides service for customers during a few days of extreme demands. These storage facilities have an aggregate firm delivery capacity of approximately 700 MMcf of gas per day.

Northwest Pipeline expansion projects

The pipeline projects listed below were completed during 2009 or are significant future pipeline projects for which we have customer commitments.

Colorado Hub Connection Project

In November 2009, Northwest Pipeline placed into service the new 27-mile, 24-inch diameter lateral referred to as the Colorado Hub Project (CHC Project). The new lateral connects the Meeker/White River Hub near Meeker, Colorado to its mainline south of Rangely, Colorado, and is estimated to cost up to $60 million. The CHC Project combined the new lateral capacity with existing mainline capacity to provide approximately 363 Mdth per day of firm transportation from various receipt points to delivery points on the mainline as far south as Ignacio, Colorado. In April 2009, the FERC issued a certificate approving the CHC Project, including the presumption of rolling in the costs of the project in any future rate case filed with the FERC.

Sundance Trail Expansion

In November 2009, Northwest Pipeline received approval from the FERC to construct approximately 16 miles of 30-inch loop between Northwest Pipeline's existing Green River and Muddy Creek compressor stations in Wyoming as well as an upgrade to Northwest Pipeline's existing Vernal compressor station, with service targeted to commence in November 2010. The total project is estimated to cost up to $65 million, including the cost of replacing the existing compression at Vernal, which will enhance the efficiency of Northwest Pipeline's system. Northwest Pipeline executed a precedent agreement to provide 150 Mdth per day of firm transportation service from the Greasewood and Meeker Hubs in Colorado for delivery to the Opal Hub in Wyoming. Northwest Pipeline has proposed to collect its maximum system rates, and has received approval from the FERC to roll-in the Sundance Trail Expansion costs in any future rate cases.

Operating statistics

The following table summarizes volume and capacity data for the Northwest Pipeline system for the periods indicated:

	2009	2008	2007
		(In TBtu)	
Total Transportation Volume	769	781	757
Average Daily Transportation Volumes	2.1	2.1	2.1
Average Daily Reserved Capacity Under Base Firm Contracts, excluding peak capacity	2.7	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts(1)	0.5	0.7	0.8

(1) Consists primarily of additional capacity created from time to time through the installation of new receipt or delivery points or the segmentation of existing mainline capacity. Such capacity is generally marketed on a short-term firm basis.

Gulfstream

Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. Gas Pipeline and Spectra Energy, through their respective subsidiaries, each holds a 50 percent ownership interest in Gulfstream and provides operating services for Gulfstream. At December 31, 2009, our equity investment in Gulfstream was $383 million.

Gulfstream expansion projects

Gulfstream placed the Phase III expansion project in service on September 1, 2008. The project extended the pipeline system into South Florida and fully subscribed the remaining 345 Mdt/d of firm capacity on the existing pipeline system on a long-term basis. The capital cost of this project was $118 million, with Gas Pipeline's share being 50 percent of such costs. Service under the Gulfstream Phase IV expansion project began during the fourth quarter of 2008. The project is fully subscribed on a long-term basis and is the first incremental expansion of Gulfstream's mainline capacity. The capital cost of this expansion was $190 million, with Gas Pipeline's share being 50 percent of such costs. The Phase V expansion involves the addition of compression to provide 35 Mdt/d of firm capacity by July 2011. The estimated capital cost of this expansion is approximately $54 million with Gas Pipeline's share being 50 percent of such cost.

WMZ

WMZ was formed to own and operate natural gas transportation and storage assets. As of December 31, 2009, we own an approximate 45.7 percent limited partnership interest and a 2 percent general partner interest in WMZ. A subsidiary of ours, Williams Pipeline GP LLC, serves as the general partner of WMZ. WMZ owns a 35 percent interest in Northwest Pipeline.

As previously discussed, our overall ownership in WMZ was affected by our restructuring transactions in 2010. WPZ intends to make an exchange offer for the publicly held units of WMZ at a future date. See "Strategic Restructuring" in Part I, Item 1 of this Form 10-K for further discussion of this potential exchange offer.

Midstream Gas & Liquids

Our Midstream segment, one of the nation's largest natural gas gatherers and processors, has primary service areas concentrated in major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, Pennsylvania, and western Canada. Midstream's primary businesses — natural gas gathering, treating, and processing; NGL fractionation, storage and transportation; and oil transportation — fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumer. NGLs, ethylene and propylene are extracted/produced at our plants, including our Canadian and Gulf Coast olefins plants. These products are used primarily for the manufacture of petrochemicals, home heating fuels and refinery feedstock.

Key variables for the Midstream business will continue to be:

- Retaining and attracting customers by continuing to provide reliable services;
- Revenue growth associated with additional infrastructure either completed or currently under construction;
- Disciplined growth in our core service areas and new step-out areas;
- Prices impacting our commodity-based processing and olefin activities.

Domestic Gathering, Processing and Treating

Our domestic gathering systems receive natural gas from producers' oil and natural gas wells and gather these volumes to gas processing, treating or redelivery facilities. Typically, natural gas, in its raw form, is not acceptable for transportation in major interstate natural gas pipelines or for commercial use as a fuel. In addition, natural gas contains various amounts of NGLs, which generally have a higher value when separated from the natural gas stream. Our processing and treating plants remove water vapor, carbon dioxide and other contaminants and our processing plants extract the NGLs and olefins. NGL products include:

- Ethane, primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for plastics;
- Propane, used for heating, fuel and as a petrochemical feedstock in the production of ethylene and propylene, another building block for petrochemical-based products such as carpets, packing materials and molded plastic parts;
- Normal butane, iso-butane and natural gasoline, primarily used by the refining industry as blending stocks for motor gasoline or as a petrochemical feedstock.

Although a significant portion of our gas processing services are performed for a volumetric-based fee, a portion of our gas processing agreements are commodity-based and include two distinct types of commodity exposure. The first type includes "keep-whole" processing agreements whereby we own the rights to the value from NGLs recovered at our plants and have the obligation to replace the lost heating value with natural gas. Under these agreements, we are exposed to the spread between NGL prices and natural gas prices. The second type consists of "percent-of-liquids" agreements whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these agreements, we are only exposed to NGL price movements. NGLs we retain in connection with both of these types of processing agreements are referred to as our equity NGL production. Our gathering and processing agreements have terms ranging from month-to-month to the life of the producing lease. Generally, our gathering and processing agreements are long-term agreements.

Our domestic gas gathering and processing customers are generally natural gas producers who have proved and/or producing natural gas fields in the areas surrounding our infrastructure. During 2009, these operations gathered and processed gas for approximately 230 gas gathering and processing customers. Our top 7 gathering and processing customers accounted for approximately 50 percent of our domestic gathering and processing revenue.

In addition to our natural gas assets, we own and operate three deepwater crude oil pipelines and own two production platforms serving the deepwater Gulf of Mexico. Our crude oil transportation revenues are typically volumetric-based fee arrangements. However, a portion of our marketing revenues are recognized from purchase and sale arrangements whereby we purchase oil from producers at the receipt points of our crude oil pipelines for an index-based price and resell the oil at delivery points at the same index-based price. Our offshore floating production platform provides centralized services to deepwater producers such as compression, separation, production handling, water removal and pipeline landings. Revenue sources have historically included a combination of fixed-fee, volumetric-based fee and cost reimbursement arrangements. Fixed fees associated with the resident production at our Devils Tower facility are recognized on a units-of-production basis.

Geographically, our Midstream natural gas assets are positioned to maximize commercial and operational synergies with our other assets. For example, most of our offshore gathering and processing assets attach and process or condition natural gas supplies delivered to the Transco pipeline. Also, our gathering and processing facilities in the San Juan basin handle approximately 87 percent of our Exploration & Production segment's equity production in this basin. Our Willow Creek plant, completed in 2009, is currently processing Exploration & Production segment's wellhead production in the Piceance basin. Our San Juan basin, southwest Wyoming, and Willow Creek systems deliver residue gas volumes into Northwest Pipeline's interstate system in addition to third-party interstate systems.

West region domestic gathering, processing and treating

We own and/or operate domestic gas gathering, processing and treating assets within the western states of Wyoming, Colorado and New Mexico.

In the Rocky Mountain area, our assets include:

- Approximately 3,500 miles of gathering pipelines with a capacity of nearly one Bcf/d and over 4,000 receipt points serving the Wamsutter and southwest Wyoming areas in Wyoming;
- Opal and Echo Springs processing plants with a combined daily inlet capacity of over 1,800 MMcf/d and NGL processing capacity of nearly 100 Mbbls/d.

In the Four Corners area, our assets include:

- Approximately 3,800 miles of gathering pipelines with a capacity of nearly two Bcf/d and approximately 6,500 receipt points serving the San Juan basin in New Mexico and Colorado;
- Ignacio, Kutz and Lybrook processing plants with a combined daily inlet capacity of 765 MMcf/d and NGL processing capacity of approximately 40 Mbbls/d. The Ignacio plant also has the capacity to produce slightly more than one Mbbls/d of liquefied natural gas;
- Milagro and Esperanza natural gas treating plants, which remove carbon dioxide but do not extract NGLs, with a combined daily inlet capacity of 750 MMcf/d. At our Milagro facility, we also use gas-driven turbines to produce approximately 60 mega-watts per day of electricity which we primarily sell into the local electrical grid.

In the Piceance basin in Colorado, our infrastructure includes:

- The Willow Creek processing plant, a 450 MMcf/d cryogenic natural gas processing plant in western Colorado's Piceance basin, designed to recover 30 Mbbls/d of NGLs. In the third quarter of 2009, construction was finished and the plant began operations. The plant is currently operating at its designed inlet capacity. In the current processing arrangement with Exploration & Production, Midstream receives a volumetric-based processing fee and a percent of the NGLs extracted.
- Parachute Lateral, a 38-mile, 30-inch diameter line transporting gas from the Parachute area to the Greasewood hub and White River hub in northwest Colorado. Our Willow Creek plant processes gas flowing through the Parachute Lateral.
- PGX pipeline delivering NGLs previously transported by truck from Exploration & Production's existing Parachute area processing plants to a major NGL transportation pipeline system.

West region expansion projects

Our major capital and expansion projects include additional capacity at our Echo Springs facility and related gathering system expansions in the Wamsutter basin. We expect to significantly increase the processing and NGL production capacities at our Echo Springs cryogenic natural gas processing plant in Wyoming. The addition of a fourth cryogenic processing train will add approximately 350 MMcf/d of processing capacity and 30 Mbbls/d of NGL production capacity, nearly doubling Echo Spring's capacities in both cases. We began construction on the fourth train at Echo Springs during the second half of 2009 and expect to bring the additional capacity online during late 2010.

Gulf region domestic gathering, processing and treating

We own and/or operate domestic gas gathering and processing assets and crude oil pipelines primarily within the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi, and Alabama. We own:

- Over 700 miles of onshore and offshore natural gas gathering pipelines with a combined capacity of approximately 3.5 Bcf/d, including:
  - The 115-mile deepwater Seahawk gas pipeline in the western Gulf of Mexico, flowing into our Markham processing plant and serving the Boomvang and Nansen field areas;

    - The 139-mile Canyon Chief gas pipeline, now including the 37-mile Blind Faith extension added in the fourth quarter of 2008, in the eastern Gulf of Mexico, flowing into our Mobile Bay processing plant and serving the Devils Tower, Triton, Goldfinger, Bass Lite and Blind Faith fields;

- Mobile Bay and Markham processing plants with a combined daily inlet capacity of 1,000 MMcf/d and NGL handling capacity of 50 Mbbls/d;

- Canyon Station production platform, which brings natural gas to specifications allowable by major interstate pipelines but does not extract NGLs, with a daily inlet capacity of 500 MMcf/d;

- Three deepwater crude oil pipelines with a combined length of 300 miles and capacity of 325 Mbbls/d including:

    - BANJO pipeline running parallel to the Seahawk gas pipeline delivering production from two producer-owned spar-type floating production systems; and delivering production to our shallow-water platform at Galveston Area Block A244 (GA-A244) and then onshore through ExxonMobil's Hoover Offshore Oil Pipeline System (HOOPS);

    - Alpine pipeline in the central Gulf of Mexico, serving the Gunnison field, and delivering production to GA-A244 and then onshore through HOOPS under a joint tariff agreement;

    - Mountaineer oil pipeline which connects to similar production sources as our Canyon Chief pipeline and, now including the new Blind Faith extension, ultimately delivering production to ChevronTexaco's Empire Terminal in Plaquemines Parish, Louisiana;

- Devils Tower production platform located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama and serving production from the Devils Tower, Triton, Goldfinger and Bass Lite fields. Located in 5,610 feet of water, it is one of the world's deepest dry tree spars. The platform, which is operated by ENI Petroleum on our behalf, is capable of handling 210 MMcf/d of natural gas and 60 Mbbls/d of oil.

Gulf region expansion projects

Our current major expansion project in the Gulf region is our Perdido Norte project located in the western deepwater of the Gulf of Mexico. The investment expands our existing infrastructure and includes a total of 184 miles of deepwater oil and gas pipeline and a 200 MMcf/d expansion of our onshore Markham gas processing facility. We expect the project to begin start-up operations in the first quarter of 2010.

Olefins

Gulf Coast region olefins

In the Gulf of Mexico region, we own a 10/12 interest in and are the operator of an ethane cracker at Geismar, Louisiana, with a total production capacity of 1.3 billion pounds of ethylene and 90 million pounds of propylene per year. Our feedstock for the ethane cracker is ethane and propane; as a result, we are exposed to the price spread between ethane and propane, and ethylene and propylene, respectively. We also own ethane and propane pipeline systems and a refinery grade propylene splitter with a production capacity of approximately 500 million pounds per year of propylene and its related pipeline system in Louisiana. At our propylene splitter, we purchase refinery grade propylene and fractionate it into polymer grade propylene and propane; as a result we are exposed to the price spread between those commodities.

Canadian region olefins

Our Canadian operations include an oil sands off-gas processing plant located near Ft. McMurray, Alberta and an NGL/olefin fractionation facility near Edmonton, Alberta. Our facilities extract liquids from the off-gas produced by a third-party oil sands bitumen upgrading process. Our arrangement with the third-party upgrader is a "keep-whole" type where we remove a mix of NGLs and olefins from the off-gas and return the equivalent heating value back to the third party in the form of natural gas. We then fractionate, treat, store, terminal and sell the propane, propylene, butane, butylenes and condensate recovered from this process. Our commodity price exposure is the spread between the price for natural gas and the NGL and olefin products we produce. We continue to be the only NGL/olefins fractionator in western Canada and the only treater/processor of oil sands upgrader off-gas. Our extraction of liquids from upgrader off-gas streams allows the upgraders to burn cleaner natural gas streams and reduce their overall air emissions. The Ft. McMurray extraction plant has processing capacity in excess of 100 MMcf/d with the ability to recover in excess of 15 Mbbls/d of olefin and NGL products.

Canadian olefin expansion projects

In Canada, we expect to begin construction in 2010 on a 261-mile, 12-inch pipeline which will transport recovered NGLs and olefins from our processing plant in Ft. McMurray to our fractionation facility near Edmonton, Alberta. The pipeline will have sufficient capacity to transport additional NGLs and olefins from the current arrangement with the third-party oil sands producer, as well as from other oil-sands producers' off-gas in the Ft. McMurray area. The project will be constructed using cash previously generated from Canadian and other international projects. We anticipate an in-service date in 2012.

In addition, a project to upgrade the value of one of the products produced at the fractionators near Edmonton, Alberta, is expected to be completed in the latter part of 2010. The new splitter and hydrotreating facilities will take the butane/butlyene mix product currently produced and further fractionate the mix product into two higher value products that are in greater demand in the market place. These new facilities are also being constructed using cash generated from Canadian and other international projects.

NGL and Olefin Marketing Services

In addition to our gathering, processing and olefin production operations, we market NGLs and olefin products to a wide range of users in the energy and petrochemical industries. The NGL marketing business transports and markets equity NGLs from the production at our domestic processing plants, and also markets NGLs on behalf of third-party NGL producers, including some of our fee-based processing customers, and the NGL volumes owned by Discovery Producer Services LLC. The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points. In order to meet sales contract obligations, we may purchase products in the spot market for resale. The majority of domestic sales are based on supply contracts of one year or less in duration. The production from our Canadian facilities is marketed in Canada and in the United States.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities: one near Conway, Kansas and the other in Baton Rouge, Louisiana that have a combined capacity in excess of 167 Mbbls/d. We also own approximately 20 million barrels of NGL storage capacity in central Kansas near Conway.

We own an equity interest in and operate the facilities of Discovery Producer Services LLC and its subsidiary Discovery Gas Transmission LLC (collectively, Discovery) through our interest in WPZ. Discovery's assets include a 600 MMcf/d cryogenic natural gas processing plant near Larose, Louisiana, a 32 Mbbls/d NGL fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system in the Gulf of Mexico.

We also own a 14.6 percent equity interest in Aux Sable Liquid Products LP and its Channahon, Illinois gas processing and NGL fractionation facility near Chicago. The facility is capable of processing up to 2.1 Bcf/d of natural gas from the Alliance Pipeline system and fractionating approximately 87 Mbbls/d of extracted liquids into NGL products.

In June 2009, we completed the formation of a new joint venture, Laurel Mountain Midstream, LLC (Laurel Mountain), in the Marcellus Shale located in southwest Pennsylvania. Our partner in the venture contributed its existing Appalachian basin gathering system, which currently has an average throughput of approximately 100 MMcf/d. In exchange for a 51 percent interest in the venture, we contributed $100 million and issued a

$26 million note payable. In 2010, we expect to significantly increase our investment in our Laurel Mountain joint venture through new gathering system infrastructure construction.

In conjunction with a long-term agreement with a major producer, we will construct a 28-mile natural gas gathering pipeline in the Marcellus Shale region that will deliver to the Transco pipeline. Construction is expected to begin on the 20-inch pipeline in the latter part of 2010, and it is expected to be placed into service during 2011. We will operate the pipeline, which represents our second significant midstream expansion in the Marcellus Shale.

We own a 49.25 percent interest in Accroven SRL which includes two 400 MMcf/d NGL extraction plants, a 50 Mbbls/d NGL fractionation plant and associated storage and refrigeration facilities. Accroven owns and operates gas processing facilities and an NGL fractionation plant for the exclusive benefit of the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA). As a result of deteriorating circumstances for our Venezuelan operations (see Note 2 of Notes to Consolidated Financial Statements), we fully impaired and recognized a $75 million charge related to an other-than-temporary loss in value of our Accroven investment. (See Note 3 of Notes to Consolidated Financial Statements.) Accroven was not part of the operations that were expropriated by the Venezuelan government in May 2009. We are currently engaged in discussions regarding the eventual disposition of Accroven.

Operating Statistics

The following table summarizes our significant operating statistics for Midstream:

	2009	2008	2007
Volumes:(1)			
Domestic gathering (TBtu)	1,068	1,013	1,045
Plant inlet natural gas (TBtu)	1,342	1,311	1,275
Domestic NGL production (Mbbls/d)(2)	164	154	163
Domestic NGL equity sales (Mbbls/d)(2)	80	80	92
Crude oil gathering (Mbbls/d)(2)	109	70	80
Canadian NGL equity sales (Mbbls/d)(2)	8	7	9
Olefin (ethylene and propylene) sales (millions of pounds)	1,728	1,605	1,401

(1) Excludes volumes associated with partially owned assets, such as our Discovery and Marcellus joint venture investments, that are not consolidated for financial reporting purposes.

(2) Annual average Mbbls/d.

WPZ

WPZ was formed in 2005 to engage in gathering, transporting, processing and treating natural gas and fractionating and storing NGLs. As of December 31, 2009, we own approximately a 23.6 percent limited partnership interest, including the interests of the general partner, Williams Partners GP LLC, which is wholly owned by us, and incentive distribution rights. WPZ provides us with an alternative source of equity capital. WPZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of both Williams and WPZ's general partner, allow us to retain control of the assets through our ownership interest in WPZ and operation of the assets. As of December 31, 2009, WPZ's asset portfolio includes Williams Four Corners LLC, certain ownership interests in Wamsutter LLC, a 60 percent interest in Discovery, three integrated NGL storage facilities near Conway, Kansas, a 50 percent interest in an NGL fractionator near Conway, Kansas, and the Carbonate Trend sour gas gathering pipeline off the coast of Alabama.

As previously discussed, our ownership in WPZ, WPZ's asset portfolio, and our future segment reporting structure were affected by our 2010 restructuring transactions.

Gas Marketing Services

Gas Marketing primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring the majority of fuel and shrink gas and hedging natural gas liquids sales for Midstream. Gas Marketing also provides similar services to third parties, such as producers and natural gas processors. In addition, Gas Marketing manages various natural gas-related contracts such as transportation and storage along with the related hedges, including certain legacy natural gas contracts and positions.

Gas Marketing's 2009 natural gas purchase volumes include 1.4 Bcf/d of gas produced by Exploration & Production and another 1.0 Bcf/d from other sources. This natural gas was in turn marketed and sold to third parties (2.1 Bcf/d) and to Midstream (0.3 Bcf/d).

Our Exploration & Production and Midstream segments may execute commodity hedges with Gas Marketing. In turn, Gas Marketing may execute offsetting derivative contracts with unrelated third parties.

Additional Business Segment Information

Our ongoing business segments are accounted for as continuing operations in the accompanying financial statements and notes to financial statements included in Part II.

Operations related to certain assets in "Discontinued Operations" have been reclassified from their traditional business segment to "Discontinued Operations" in the accompanying financial statements and notes to financial statements included in Part II.

We perform certain management, legal, financial, tax, consultation, information technology, administrative and other services for our subsidiaries.

Our principal sources of cash are from dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, interest payments from subsidiaries on cash advances and, if needed, external financings, sales of master limited partnership units to the public, and net proceeds from asset sales. The amount of dividends available to us from subsidiaries largely depends upon each subsidiary's earnings and operating capital requirements. The terms of certain of our subsidiaries' borrowing arrangements limit the transfer of funds to us.

We believe that we have adequate sources and availability of raw materials and commodities for existing and anticipated business needs. In support of our energy commodity activities, primarily conducted through Gas Marketing Services, our counterparties require us to provide various forms of credit support such as margin, adequate assurance amounts and pre-payments for gas supplies. Our pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory agencies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

REGULATORY MATTERS

Exploration & Production. Our Exploration & Production business is subject to various federal, state and local laws and regulations on taxation and payment of royalties, and the development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves.

Gas Pipeline. Gas Pipeline's interstate transmission and storage activities are subject to FERC regulation under the Natural Gas Act of 1938 (NGA) and under the Natural Gas Policy Act of 1978, and, as such, its rates and charges for the transportation of natural gas in interstate commerce, its accounting, and the extension, enlargement or abandonment of its jurisdictional facilities, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, and the Pipeline Safety Improvement Act of 2002, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC Standards of Conduct govern how our interstate pipelines communicate and do business with gas marketing employees. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit gas marketing functions.

Each of our interstate natural gas pipeline companies establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are:

- Costs of providing service, including depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Volume throughput assumptions.

The allowed rate of return is determined in each rate case. Rate design and the allocation of costs between the demand and commodity rates also impact profitability. As a result of these proceedings, certain revenues previously collected may be subject to refund.

Pipeline Integrity Regulations

Transco and Northwest Pipeline have developed Integrity Management Plans that meet the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") final rule pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. In meeting the integrity regulations, Transco and Northwest Pipeline have identified high-consequence areas, completed baseline assessment plans, and are on schedule to complete the required assessments within specified timeframes. Currently, Transco and Northwest Pipeline estimate that the cost to perform required assessments and remediation will be primarily capital and range between $150 million and $220 million and between $65 million and $85 million, respectively, over the remaining assessment period of 2010 through 2012. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through rates.

Midstream Gas & Liquids. For our Midstream segment, onshore gathering is subject to regulation by states in which we operate and offshore gathering is subject to the Outer Continental Shelf Lands Act (OCSLA). Of the states where Midstream gathers gas, currently only Texas actively regulates gathering activities. Texas regulates gathering primarily through complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Although offshore gathering facilities are not subject to the NGA, offshore transmission pipelines are subject to the NGA, and in recent years the FERC has taken a broad view of offshore transmission, finding many shallow-water pipelines to be jurisdictional transmission. Most gathering facilities offshore are subject to the OCSLA, which provides in part that outer continental shelf pipelines "must provide open and nondiscriminatory access to both owner and nonowner shippers."

Midstream also owns interests in and operates two offshore transmission pipelines that are regulated by the FERC because they are deemed to transport gas in interstate commerce. Black Marlin Pipeline Company provides transportation service for offshore Texas production in the High Island area and redelivers that gas to intrastate pipeline interconnects near Texas City. Discovery provides transportation service for offshore Louisiana production from the South Timbalier, Grand Isle, Ewing Bank and Green Canyon (deepwater) areas to an onshore processing facility and downstream interconnect points with major interstate pipelines. FERC regulation requires all terms and conditions of service, including the rates charged, to be filed with and approved by the FERC before any changes can go into effect.

Our Midstream Canadian assets are regulated by the Energy Resources Conservation Board (ERCB) and Alberta Environment. The regulatory system for the Alberta oil and gas industry incorporates a large measure of self-regulation, providing that licensed operators are held responsible for ensuring that their operations are conducted in accordance with all provincial regulatory requirements. For situations in which noncompliance with the applicable regulations is at issue, the ERCB and Alberta Environment have implemented an enforcement process with escalating consequences.

Gas Marketing Services. Our Gas Marketing business is subject to a variety of laws and regulations at the local, state and federal levels, including the FERC and the Commodity Futures Trading Commission regulations. In addition, natural gas markets continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations. We are also subject to various federal and state actions and investigations regarding, among other things, market structure, behavior of market participants, market prices, and reporting to trade publications. We may be liable for refunds and other damages and penalties as a result of ongoing actions and investigations. The outcome of these matters could affect our creditworthiness and ability to perform contractual obligations as well as other market participants' creditworthiness and ability to perform contractual obligations to us.

See Note 16 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our generation facilities, processing facilities, natural gas pipelines, and exploration and production operations are subject to federal environmental laws and regulations as well as the state and tribal laws and regulations adopted by the jurisdictions in which we operate. We could incur liability to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil, or water, as well as liability for cleanup costs. Materials could be released into the environment in several ways including, but not limited to:

- From a well or drilling equipment at a drill site;
- Leakage from gathering systems, pipelines, processing or treating facilities, transportation facilities and storage tanks;
- Damage to oil and gas wells resulting from accidents during normal operations;
- Blowouts, cratering and explosions.

Because the requirements imposed by environmental laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, we may be liable for environmental damage caused by former operators of our properties.

We believe compliance with environmental laws and regulations will not have a material adverse effect on capital expenditures, earnings or competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, fines and penalties, and creating the need to seek relief from the FERC for rate increases to recover the costs of certain capital expenditures and operation and maintenance expenses.

For a discussion of specific environmental issues, see "Environmental" under Management's Discussion and Analysis of Financial Condition and Results of Operations and "Environmental Matters" in Note 16 of our Notes to Consolidated Financial Statements.

COMPETITION

Exploration & Production. Our Exploration & Production segment competes with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

Gas Pipeline. The natural gas industry has undergone significant change over the past two decades. A highly-liquid competitive commodity market in natural gas and increasingly competitive markets for natural gas services, including competitive secondary markets in pipeline capacity, have developed. As a result, pipeline capacity is being used more efficiently, and peaking and storage services are increasingly effective substitutes for annual pipeline capacity.

Local distribution company (LDC) and electric industry restructuring by states have affected pipeline markets. Pipeline operators are increasingly challenged to accommodate the flexibility demanded by customers and allowed under tariffs, but the changes implemented at the state level have not required renegotiation of LDC contracts. The state plans have in some cases discouraged LDCs from signing long-term contracts for new capacity.

States are in the process of developing new energy plans that may require utilities to encourage energy saving measures and diversify their energy supplies to include renewable sources. This could lower the growth of gas demand.

These factors have increased the risk that customers will reduce their contractual commitments for pipeline capacity. Future utilization of pipeline capacity will also depend on competition from LNG imported into markets and new pipelines from the Rockies and other new producing areas, many of which are utilizing master limited partnership structures with a lower cost of capital, and on growth of natural gas demand.

Midstream Gas & Liquids. In our Midstream segment, we face regional competition with varying competitive factors in each basin. Our gathering and processing business competes with other midstream companies, interstate and intrastate pipelines, producers and independent gatherers and processors. We primarily compete with five to ten companies across all basins in which we provide services. Numerous factors impact any given customer's choice of a gathering or processing services provider, including rate, location, term, timeliness of services to be provided, pressure obligations and contract structure. We also compete in recruiting and retaining skilled employees. By virtue of the master limited partnership structure, WPZ provides us with an alternative source of capital, which helps us compete against other master limited partnerships for midstream projects.

Gas Marketing Services. In our Gas Marketing Services segment, we compete directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities, and natural gas producers. We also compete with brokerage houses, energy hedge funds and other energy-based companies offering similar services.

EMPLOYEES

At February 1, 2010, we had approximately 4,801 full-time employees. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 18 of our Notes to Consolidated Financial Statements for amounts of revenues during the last three fiscal years from external customers attributable to the United States and all foreign countries. Also see Note 18 of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, located in the United States and all foreign countries.

Item 1A. ***Risk Factors***

FORWARD-LOOKING STATEMENTS/RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain matters contained in this report include "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. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "targets," "planned," "potential," "projects," "scheduled," "will" or other similar expressions. These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Seasonality of certain business segments;
- Natural gas and natural gas liquids prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas reserves), market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- The strength and financial resources of our competitors;
- Development of alternative energy sources;
- The impact of operational and development hazards;
- Costs of, changes in, or the results of laws, government regulations (including proposed climate change legislation), environmental liabilities, litigation, and rate proceedings;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Acts of terrorism;
- Additional risks described in our filings with the Securities and Exchange Commission.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors are described in the following section.

RISK FACTORS

You should carefully consider the following risk factors in addition to the other information in this report. Each of these factors could adversely affect our business, operating results, and financial condition, as well as adversely affect the value of an investment in our securities.

Risks Related to the Restructuring

We did not seek a vote of our shareholders in connection with the restructuring. If there is a determination that such a vote was required, the resulting consequences could impact us.

Section 271 of the Delaware General Corporation Law (the "DGCL") generally requires a corporation to obtain authorization from the holders of a majority of its outstanding shares if the corporation intends to sell all or substantially all of its assets. We do not believe the restructuring constituted a sale of "all or substantially all" of our assets because of, among other things, the portion of our assets involved, the significance of our assets and businesses that were not transferred and the facts that we retain control of all of the assets involved and over an 80% interest in the cash flows therefrom. As such, we did not seek a vote of our shareholders in connection with the restructuring. There is a limited body of Delaware case law interpreting the phrase "all or substantially all," and there is no precise established definition. We cannot assure you that the restructuring did not constitute a sale of "all or substantially all" of our assets and, therefore, that a shareholder vote was not required. If such a shareholder vote were determined to be required, the resulting consequences could impact us and could include (among other consequences) our shareholders asserting claims against us, some or all of which could ultimately be successful.

We may not realize the anticipated benefits from the restructuring.

We may not realize the benefits that we anticipate from the Dropdown for a number of reasons, including, but not limited to, if any of the matters identified as risks in this Risk Factors section were to occur. If we do not realize the anticipated benefits from the restructuring for any reason, our business may be materially adversely affected.

Risks Inherent to our Industry and Business

The long-term financial condition of our Gas Pipeline and Midstream businesses is dependent on the continued availability of natural gas supplies in the supply basins that we access, demand for those supplies in our traditional markets, and the prices of and market demand for natural gas.

The development of the additional natural gas reserves that are essential for our Gas Pipeline and Midstream businesses to thrive requires significant capital expenditures by others for exploration and development drilling and the installation of production, gathering, storage, transportation and other facilities that permit natural gas to be produced and delivered to our pipeline systems. Low prices for natural gas, regulatory limitations, including environmental regulations, or the lack of available capital for these projects could adversely affect the development and production of additional reserves, as well as gathering, storage, pipeline transportation and import and export of natural gas supplies, adversely impacting our ability to fill the capacities of our gathering, transportation and processing facilities.

Production from existing wells and natural gas supply basins with access to our pipeline and gathering systems will also naturally decline over time. The amount of natural gas reserves underlying these wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. Additionally, the competition for natural gas supplies to serve other markets could reduce the amount of natural gas supply for our customers. Accordingly, to maintain or increase the contracted capacity or the volume of natural gas transported on or gathered through our pipelines and cash flows associated with the gathering and transportation of natural gas, our customers must compete with others to obtain adequate supplies of natural gas. In addition, if natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted on a short-term basis, as well as with respect to our long-term recontracting activities. If new supplies of natural gas are not obtained to replace the natural decline in volumes from existing supply areas, if natural gas supplies are diverted to serve other markets, or if environmental regulators restrict new natural gas drilling, the overall volume of natural gas transported, gathered, and stored on our system would decline, which could have a material adverse effect on our business, financial condition and results of operations. In addition, new LNG import facilities built near our markets could result in less demand for our gathering and transportation facilities.

Significant prolonged changes in natural gas prices could affect supply and demand and cause a termination of our transportation and storage contracts or a reduction in throughput on our system.

Higher natural gas prices over the long term could result in a decline in the demand for natural gas and, therefore, in our long-term transportation and storage contracts or throughput on our Gas Pipelines' systems. Also, lower natural gas prices over the long term could result in a decline in the production of natural gas resulting in reduced contracts or throughput on our Gas Pipelines' systems. As a result, significant prolonged changes in natural gas prices could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Prices for NGLs, natural gas and other commodities are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses.

Our revenues, operating results, future rate of growth and the value of certain segments of our businesses depend primarily upon the prices of NGLs, natural gas, or other commodities, and the differences between prices of these commodities. Price volatility and relative price levels may impact both the amount we receive for our products and services and the volume of products and services we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital.

The markets for NGLs, natural gas and other commodities are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- Worldwide and domestic supplies of and demand for natural gas, NGLs, petroleum, and related commodities;
- Turmoil in the Middle East and other producing regions;
- The activities of the Organization of Petroleum Exporting Countries;
- Terrorist attacks on production or transportation assets;
- Weather conditions;
- The level of consumer demand;
- The price and availability of other types of fuels;
- The availability of pipeline capacity;
- Supply disruptions, including plant outages and transportation disruptions;
- The price and level of foreign imports;

- Domestic and foreign governmental regulations and taxes;
- Volatility in the natural gas markets;
- The overall economic environment;
- The credit of participants in the markets where products are bought and sold;
- The adoption of regulations or legislation relating to climate change.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts may consist of wholesale contracts to buy and sell commodities, including contracts for natural gas, NGLs and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will suffer a loss. A general downturn in the economy and tightening of global credit markets could cause more of our counterparties to fail to perform than we have expected.

Significant capital expenditures are required to replace our reserves.

Our exploration, development and acquisition activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and debt and equity issuances. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of natural gas, and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may not be able to access additional bank debt, issue debt or equity securities or access other methods of financing on an economic basis to meet our capital expenditure budget. As a result, our capital expenditure plans may have to be adjusted.

Failure to replace reserves may negatively affect our business.

The growth of our Exploration & Production business depends upon our ability to find, develop or acquire additional natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis. If natural gas prices increase, our costs for additional reserves would also increase; conversely if natural gas prices decrease, it could make it more difficult to fund the replacement of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

Our past success rate for drilling projects should not be considered a predictor of future commercial success. We do not always encounter commercially productive reservoirs through our drilling operations. The new wells we drill or participate in may not be productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. Further, our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, skilled labor, capital or transportation;
- Unexpected drilling conditions or problems;
- Regulations and regulatory approvals;
- Changes or anticipated changes in energy prices;
- Compliance with environmental and other governmental requirements.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates, oil and gas prices or assumptions as to future natural gas prices may lead to decreased earnings, losses, or impairment of oil and gas assets, including related goodwill.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are "proved reserves" are those estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions, but should not be considered as a guarantee of results for future drilling projects.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represent estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings. The revisions could also possibly affect the evaluation of Exploration & Production's goodwill for impairment purposes. At December 31, 2009, we had approximately $1 billion of goodwill on our balance sheet.

Certain of our services are subject to long-term, fixed-price contracts that are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts.

Our Gas Pipeline and Midstream businesses provide some services pursuant to long-term, fixed price contracts. It is possible that costs to perform services under such contracts will exceed the revenues we collect for our services. Although most of the services provided by our interstate gas pipelines are priced at cost-based rates that are subject to adjustment in rate cases, under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate" that may be above or below the FERC regulated cost-based rate for that service. These "negotiated rate" contracts are not generally subject to adjustment for increased costs that could be produced by inflation or other factors relating to the specific facilities being used to perform the services.

We may not be able to maintain or replace expiring natural gas transportation and storage contracts at favorable rates or on a long-term basis.

Our primary exposure to market risk for our Gas Pipelines occurs at the time the terms of their existing transportation and storage contracts expire and are subject to termination. Although none of our Gas Pipelines' material contracts are terminable in 2010, upon expiration of the terms we may not be able to extend contracts with existing customers to obtain replacement contracts at favorable rates or on a long-term basis. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- The level of existing and new competition to deliver natural gas to our markets;
- The growth in demand for natural gas in our markets;
- Whether the market will continue to support long-term firm contracts;
- Whether our business strategy continues to be successful;
- The level of competition for natural gas supplies in the production basins serving us;
- The effects of state regulation on customer contracting practices.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our risk measurement and hedging activities might not be effective and could increase the volatility of our results.

Although we have systems in place that use various methodologies to quantify commodity price risk associated with our businesses, these systems might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified.

In an effort to manage our financial exposure related to commodity price and market fluctuations, we have entered into contracts to hedge certain risks associated with our assets and operations. In these hedging activities, we have used fixed-price, forward, physical purchase and sales contracts, futures, financial swaps and option contracts traded in the over-the-counter markets or on exchanges. Nevertheless, no single hedging arrangement can adequately address all risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist. While we attempt to manage counterparty credit risk within guidelines established by our credit policy, we may not be able to successfully manage all credit risk and as such, future cash flows and results of operations could be impacted by counterparty default.

Our use of hedging arrangements through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for NGLs and natural gas on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for NGLs or natural gas were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

- Volumes are less than expected;
- The hedging instrument is not perfectly effective in mitigating the risk being hedged;
- The counterparties to our hedging arrangements fail to honor their financial commitments.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers or the loss of any contracted volumes could result in a decline in our business.

Our Gas Pipeline and Midstream businesses rely on a limited number of customers for a significant portion of their revenues. Although some of these customers are subject to long-term contracts, extensions or replacements of these contracts may not be renegotiated favorable terms, if at all. The loss of even a portion of the revenues from natural gas, NGLs or contracted volumes, as applicable, supplied by these customers, as a result of competition, creditworthiness, inability to negotiate extensions or replacements of contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations and cash flows, unless we are able to generate comparable revenues from other sources.

We are exposed to the credit risk of our customers, and our credit risk management may not be adequate to protect against such risk.

We are exposed to risk of loss resulting from nonpayment and/or nonperformance by our customers in the ordinary course of our business. Generally our customers are either rated investment grade or otherwise considered credit worthy, or they are required to make pre-payments or otherwise provide security to satisfy credit concerns. However, our credit procedures and policies may not be adequate to fully eliminate customer credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results for the period in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Competition in the markets in which we operate may adversely affect our results of operations.

We have numerous competitors in all aspects of our businesses, and additional competitors may enter our markets. Other companies with which we compete may be able to respond more quickly to new laws or regulations or emerging technologies, or to devote greater resources to the construction, expansion or refurbishment of their facilities than we can. In addition, current or potential competitors may make strategic acquisitions or have greater financial resources than we do, which could affect our ability to make investments or acquisitions. There can be no assurance that we will be able to compete successfully against current and future competitors and any failure to do so could have a material adverse effect on our businesses and results of operations.

The failure of new sources of natural gas production or LNG import terminals to be successfully developed in North America could increase natural gas prices and reduce the demand for our services.

New sources of natural gas production in the United States and Canada, particularly in areas of shale development are expected to become an increasingly significant component of future U.S. natural gas supplies in North America. Additionally, increases in LNG supplies are expected to be imported through new LNG import terminals, particularly in the Gulf Coast region. If these additional sources of supply are not developed, natural gas prices could increase and cause consumers of natural gas to turn to alternative energy sources, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our drilling, production, gathering, processing, storage and transporting activities involve numerous risks that might result in accidents, and other operating risks and hazards.

Our operations are subject to all the risks and hazards typically associated with the development and exploration for, and the production and transportation of oil and gas. These operating risks include, but are not limited to:

- Fires, blowouts, cratering and explosions;
- Uncontrolled releases of oil, natural gas, NGLs or well fluids;
- Collapse of NGL storage caverns;

- Operator error;
- Pollution and other environmental risks;
- Hurricanes, tornadoes, floods, fires, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;
- Damages to pipelines and pipeline blockages;
- Damage inadvertently caused by third party activity, such as operation of construction equipment;
- Risks related to truck and rail loading and unloading;
- Risks related to operating in a marine environment;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our pipelines in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property, and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on segments of our pipeline infrastructure. Potential customer impacts arising from service interruptions on segments of our pipeline infrastructure could include limitations on the pipeline's ability to satisfy customer requirements, obligations to provide reservations charge credits to customers in times of constrained capacity, and solicitation of existing customers by others for potential new pipeline projects that would compete directly with existing services. Such circumstances could materially impact our ability to meet contractual obligations and retain customers, with a resulting negative impact on our business, financial condition, results of operations and cash flows.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the ability of the insurers we do use to satisfy our claims.

We are not fully insured against all risks inherent to our business, including environmental accidents that might occur. In addition, we do not maintain business interruption insurance in the type and amount to cover all possible risks of loss. We currently maintain excess liability insurance with limits of $610 million per occurrence and in the aggregate annually and a deductible of $2 million per occurrence. This insurance covers us, our subsidiaries and certain of our affiliates for legal and contractual liabilities arising out of bodily injury, personal injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability for full limits, with the first $135 million of insurance also providing gradual pollution liability coverage for natural gas and NGL operations. Pollution liability coverage excludes: release of pollutants subsequent to their disposal; release of substances arising from the combustion of fuels that result in acidic deposition, and testing, monitoring, clean-up, containment, treatment or removal of pollutants from property owned, occupied by, rented to, used by or in the care, custody or control of us, our subsidiaries and certain of our affiliates.

We do not insure onshore underground pipelines for physical damage, except at river crossings and at certain locations such as compressor stations. We maintain coverage of $300 million per occurrence for physical damage to onshore assets and resulting business interruption caused by terrorist acts. We also maintain coverage of $100 million per occurrence for physical damage to offshore assets caused by terrorist acts, except for our Devils Tower spar where we maintain limits of $300 million per occurrence for property damage caused by terrorist acts and $105 million per occurrence for resulting business interruption. Also, all of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. Changes in the insurance markets subsequent to hurricane losses in recent years have impacted named windstorm insurance coverage, rates and availability for Gulf of Mexico area exposures, and we may elect to self insure a portion of our asset portfolio. We cannot assure you that we will in the future be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, certain insurance companies that provide coverage to us, including American International Group, Inc., have experienced negative developments that could impair their ability to pay any of our potential claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

Execution of our capital projects subjects us to construction risks, increases in labor and materials costs and other risks that may adversely affect financial results.

A significant portion of any growth in our Gas Pipeline and Midstream businesses is accomplished through the construction of new pipelines, processing and storage facilities, as well as the expansion of existing facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- The ability to obtain necessary approvals and permits by regulatory agencies on a timely basis and on acceptable terms;
- The availability of skilled labor, equipment, and materials to complete expansion projects;
- Potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project;
- Impediments on our ability to acquire rights-of-way or land rights on a timely basis and on acceptable terms;
- The ability to construct projects within estimated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials, labor, or other factors beyond our control, that may be material;
- The ability to access capital markets to fund construction projects.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve expected investment return, which could adversely affect results of operations, financial position or cash flows.

Our costs and funding obligations for our defined benefit pension plans and costs for our other post-retirement benefit plans are affected by factors beyond our control.

We have defined benefit pension plans covering substantially all of our U.S. employees and other post-retirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors we control, including changes to pension plan benefits, as well as factors outside of our control, such as asset returns, interest rates and changes in pension laws. Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition and results of operations.

Two of our subsidiaries act as the respective general partners of two different publicly-traded limited partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P. As such, those subsidiaries' operations may involve a greater risk of liability than ordinary business operations.

One of our subsidiaries acts as the general partner of WPZ and another subsidiary of ours acts as the general partner of WMZ. Each of these subsidiaries that act as the general partner of a publicly-traded limited partnership may be deemed to have undertaken fiduciary obligations with respect to the limited partnership of which it serves as the general partner and to the limited partners of such limited partnership. Activities determined to involve fiduciary obligations to other persons or entities typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interests is found to exist. Our control of the general partners of two different publicly traded partnerships may increase the possibility of claims of breach of fiduciary duties, including claims brought due to conflicts of interest (including conflicts of interest that may arise (i) between the two publicly-traded partnerships as well as (ii) between a publicly-traded partnership, on the one hand, and its general partner and that general partner's affiliates, including us, on the other hand). Any liability resulting from such claims could be material.

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent registered public accounting firms, and retirement plan practices. We cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies or the energy industry or in our operations specifically. In addition, the Financial Accounting Standards Board (FASB) or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations, and financial condition.

Our investments and projects located outside of the United States expose us to risks related to the laws of other countries, and the taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments. These risks might delay or reduce our realization of value from our international projects.

We currently own and might acquire and/or dispose of material energy-related investments and projects outside the United States. The economic and political conditions in certain countries where we have interests or in which we might explore development, acquisition or investment opportunities present risks of delays in construction and interruption of business, as well as risks of war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States. The uncertainty of the legal environment in certain foreign countries in which we develop or acquire projects or make investments could make it more difficult to obtain nonrecourse project financing or other financing on suitable terms, could adversely affect the ability of certain customers to honor their obligations with respect to such projects or investments and could impair our ability to enforce our rights under agreements relating to such projects or investments.

Operations and investments in foreign countries also can present currency exchange rate and convertibility, inflation and repatriation risk. In certain situations under which we develop or acquire projects or make investments, economic and monetary conditions and other factors could affect our ability to convert to U.S. dollars our earnings denominated in foreign currencies. In addition, risk from fluctuations in currency exchange rates can arise when our foreign subsidiaries expend or borrow funds in one type of currency, but receive revenue in another. In such cases, an adverse change in exchange rates can reduce our ability to meet expenses, including debt service obligations. We may or may not put contracts in place designed to mitigate our foreign currency exchange risks. We have some exposures that are not hedged and which could result in losses or volatility in our results of operations.

Our operating results for certain segments of our business might fluctuate on a seasonal and quarterly basis.

Revenues from certain segments of our business can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and pipeline systems and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

Additionally, changes in the price of natural gas could benefit one of our business units, but disadvantage another. For example, our Exploration & Production business may benefit from higher natural gas prices, and Midstream, which uses gas as a feedstock, may not.

Risks Related to Strategy and Financing

Our debt agreements impose restrictions on us that may adversely affect our ability to operate our business.

Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, merge, sell substantially all of our assets, make certain distributions, and incur additional debt. In addition, our debt agreements contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by many events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired. We cannot assure you that our future operating results will be sufficient to comply with the covenants or, in the event of a default under any of our debt agreements, to remedy that default.

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance existing debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Future disruptions in the global credit markets may make equity and debt markets less accessible, create a shortage in the availability of credit and lead to credit market volatility.

In 2008, public equity markets experienced significant declines and global credit markets experienced a shortage in overall liquidity and a resulting disruption in the availability of credit. Future disruptions in the global financial marketplace, including the bankruptcy or restructuring of financial institutions, may make equity and debt markets inaccessible and adversely affect the availability of credit already arranged and the availability and cost of credit in the future. We have availability under our existing bank credit facilities, but our ability to borrow under those facilities could be impaired if one or more of our lenders fail to honor its contractual obligation to lend to us.

Adverse economic conditions could adversely affect our results of operations.

A slowdown in the economy has the potential to negatively impact our businesses in many ways. Included among these potential negative impacts are reduced demand and lower prices for our products and services, increased difficulty in collecting amounts owed to us by our customers and a reduction in our credit ratings (either due to tighter rating standards or the negative impacts described above), which could result in reducing our access to credit markets, raising the cost of such access or requiring us to provide additional collateral to our counterparties.

A downgrade of our credit ratings could impact our liquidity, access to capital and our costs of doing business, and maintaining current credit ratings is under the control of independent third parties.

A downgrade of our credit rating might increase our cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. Our ability to access capital markets would also be limited by a downgrade of our credit rating and other disruptions. Such disruptions could include:

- Economic downturns;
- Deteriorating capital market conditions;
- Declining market prices for natural gas, natural gas liquids and other commodities;
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- The overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. The analysis includes a number of criteria including, but not limited to, business composition, market and operational risks, as well as various financial tests. Credit rating agencies continue to review the criteria for industry sectors and various debt ratings and may make changes to those criteria from time to time. Our corporate family credit rating and the credit ratings of Transco and Northwest Pipeline are rated investment grade by Standard & Poor's, Moody's Corporation, and Fitch Ratings, Ltd., and our senior unsecured debt ratings are rated investment grade by Moody's and Fitch. Credit ratings are not recommendations to buy, sell or hold investments in the rated entity. Ratings are subject to revision or withdrawal at any time by the ratings agencies, and no assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their criteria for investment grade ratios or that our senior unsecured debt rating will be raised to investment grade by all of the credit rating agencies.

Risks Related to Regulations that Affect our Industry

Our natural gas sales, transmission, and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on our results of operations.

Our interstate natural gas sales, transportation, and storage operations conducted through our Gas Pipelines business are subject to the FERC's rules and regulations in accordance with the NGA and the Natural Gas Policy Act of 1978. The FERC's regulatory authority extends to:

- Transportation and sale for resale of natural gas in interstate commerce;
- Rates, operating terms and conditions of service, including initiation and discontinuation of services;
- Certification and construction of new facilities;
- Acquisition, extension, disposition or abandonment of facilities;
- Accounts and records;
- Depreciation and amortization policies;
- Relationships with marketing functions within Williams involved in certain aspects of the natural gas business;
- Market manipulation in connection with interstate sales, purchases or transportation of natural gas.

Regulatory actions in these areas can affect our business in many ways, including decreasing tariff rates and revenues, decreasing volumes in our pipelines, increasing our costs and otherwise altering the profitability of our business. Regulatory decisions could also affect our costs for compression, processing and dehydration of natural gas, which could have a negative effect on our results of operations.

The FERC has taken certain actions to strengthen market forces in the natural gas pipeline industry that have led to increased competition throughout the industry. In a number of key markets, interstate pipelines are now facing competitive pressure from other major pipeline systems, enabling local distribution companies and end users to choose a transportation provider based on considerations other than location.

We are subject to risks associated with climate change.

There is a growing belief that emissions of greenhouse gases (GHGs) may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

Costs of environmental liabilities and complying with existing and future environmental regulations, including those related to climate change and greenhouse gas emissions, could exceed our current expectations.

Our operations are subject to extensive environmental regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, extraction, transportation, treatment and disposal of hazardous substances and wastes, in connection with spills, releases and emissions of various substances into the environment, and in connection with the operation, maintenance, abandonment and reclamation of our facilities. Various governmental authorities, including the U.S. Environmental Protection Agency (EPA) and analogous state agencies and the United States Department of Homeland Security, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, and the issuance of injunctions limiting or preventing some or all of our operations.

Compliance with environmental laws requires significant expenditures, including clean up costs and damages arising out of contaminated properties. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations for the remediation of contaminated areas and in connection with spills or releases of natural gas and wastes on, under, or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. Although we do not expect that the costs of complying with current environmental laws will have a material adverse effect on our financial condition or results of operations, no assurance can be given that the costs of complying with environmental laws in the future will not have such an effect.

Legislative and regulatory responses related to GHGs and climate change creates the potential for financial risk. The United States Congress and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, federal, and international proposals to reduce or mitigate GHG emissions.

Several bills have been introduced in the United States Congress that would compel GHG emission reductions. In June of 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act" which is intended to decrease annual GHG emissions through a variety of measures, including a "cap and trade" system which limits the amount of GHGs that may be emitted and incentives to reduce the nation's dependence on traditional energy sources. The U.S. Senate is currently considering similar legislation, and numerous states have also announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. This determination is the latest in a series of EPA actions in 2009 which could ultimately lead to the direct regulation of GHG emissions in our industry by the EPA under the Clean Air Act. While it is not clear whether or when any federal or state climate change laws or regulations will be passed, any of these actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively impact our cost of and access to capital.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change. Our regulatory rate structure and our contracts with customers might not necessarily allow us to recover capital costs we incur to comply with the new environmental regulations. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for certain development projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

If third-party pipelines and other facilities interconnected to our pipeline and facilities become unavailable to transport natural gas and NGLs or to treat natural gas, our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipeline and facilities for the benefit of our customers. Because we do not own these third-party pipelines or facilities, their continuing operation is not within our control. If these pipelines or other facilities were to become unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to the pipelines or facilities, reduced operating pressures, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or other causes, we and our customers would have reduced capacity to transport, store or deliver natural gas or NGL products to end use markets or to receive deliveries of mixed NGLs, thereby reducing our revenues. Further, although there are laws and regulations designed to encourage competition in wholesale market transactions, some companies may fail to provide fair and equal access to their transportation systems or may not provide sufficient transportation capacity for other market participants. Any temporary or permanent interruption at any key pipeline interconnect or in operations on third-party pipelines or facilities that would cause a material reduction in volumes transported on our pipelines or our gathering systems or processed, fractionated, treated or stored at our facilities could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Specifically, the Colorado Oil & Gas Conservation Commission has enacted new rules in 2009 which increased our costs of permitting and environmental compliance and the time required to obtain permits, which may have a material effect on our results of operations.

Legal and regulatory proceedings and investigations relating to the energy industry and capital markets have adversely affected our business and may continue to do so.

Public and regulatory scrutiny of the energy industry and of the capital markets has resulted in increased regulation being either proposed or implemented. Such scrutiny has also resulted in various inquiries, investigations and court proceedings in which we are a named defendant. Both the shippers on our pipelines and regulators have rights to challenge the rates we charge under certain circumstances. Any successful challenge could materially affect our results of operations.

Certain inquiries, investigations and court proceedings are ongoing and continue to adversely affect our business as a whole. We might see these adverse effects continue as a result of the uncertainty of these ongoing inquiries and proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation, which might be materially adverse to the operation of our business and our revenues and net income or increase our operating costs in other ways. Current legal proceedings or other matters against us arising out of our ongoing and discontinued operations including environmental matters, suits, regulatory appeals and similar matters might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

Risks Related to Employees, Outsourcing of Noncore Support Activities, and Technology

Institutional knowledge residing with current employees nearing retirement eligibility might not be adequately preserved.

In certain segments of our business, institutional knowledge resides with employees who have many years of service. As these employees reach retirement age, we may not be able to replace them with employees of comparable knowledge and experience. In addition, we may not be able to retain or recruit other qualified individuals, and our efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to us.

Failure of or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Some studies indicate a high failure rate of outsourcing relationships. Although we have taken steps to build a cooperative and mutually beneficial relationship with our outsourcing providers and to closely monitor their performance, a deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Certain of our accounting, information technology, application development, and help desk services are currently provided by an outsourcing provider from service centers outside of the United States. The economic and political conditions in certain countries from which our outsourcing providers may provide services to us present similar risks of business operations located outside of the United States previously discussed, including risks of interruption of business, war, expropriation, nationalization, renegotiation, trade sanctions or nullification of existing contracts and changes in law or tax policy, that are greater than in the United States.

Risks Related to Weather, other Natural Phenomena and Business Disruption

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations, including those located offshore, can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures, making it more difficult for us to realize the historic rates of return associated with these assets and operations. Insurance may be inadequate, and in some instances, we have been unable to obtain insurance on commercially reasonable terms, or insurance may not be available. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading to either increased investment or decreased revenues.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport or distribute natural gas, natural gas liquids or other commodities. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

We own property in 32 states plus the District of Columbia in the United States and in Argentina, Canada, Venezuela, and Colombia.

Gas Marketing's primary assets are its term contracts, related systems and technological support. In our Gas Pipeline and Midstream segments, we generally own our facilities, although a substantial portion of our pipeline and gathering facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others. In our Exploration & Production segment, the majority of our ownership interest in exploration and production properties is held as working interests in oil and gas leaseholds.

Item 3. *Legal Proceedings*

The information called for by this item is provided in Note 16 of the Notes to Consolidated Financial Statements of this report, which information is incorporated by reference into this item.

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

None.

Executive Officers of the Registrant

The name, age, period of service, and title of each of our executive officers as of February 17, 2009, are listed below.

Alan S. Armstrong................ Senior Vice President, Midstream
Age: 47

Position held since February 2002.

Mr. Armstrong acts as President of our Midstream business unit. From 1999 to February 2002, Mr. Armstrong was Vice President, Gathering and Processing for Midstream. From 1998 to 1999 he was Vice President, Commercial Development for Midstream. Mr. Armstrong serves as a director and Senior Vice President, Midstream, of Williams Partners GP LLC, the general partner of Williams Partners L.P.

James J. Bender . . . . Senior Vice President and General Counsel
Age: 53

Position held since December 2002.

Prior to joining us, Mr. Bender was Senior Vice President and General Counsel with NRG Energy, Inc., a position held since June 2000, prior to which he was Vice President, General Counsel and Secretary of NRG Energy Inc. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003. Mr. Bender has served as the General Counsel of Williams Partners GP LLC, the general partner of Williams Partners L.P. since February 2005 and of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P. since August 2007.

Donald R. Chappel . . . . Senior Vice President and Chief Financial Officer
Age: 58

Position held since April 2003.

Prior to joining us, Mr. Chappel held various financial, administrative and operational leadership positions. Mr. Chappel serves as Chief Financial Officer and a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., and as Chief Financial Officer and a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.

Robyn L. Ewing. . . . . Senior Vice President, Strategic Services and Administration and Chief Administrative Officer
Age: 54

Position held since March 2008.

From 2004 to 2008 Ms. Ewing was Vice President of Human Resources. Prior to joining Williams, Ms. Ewing worked at MAPCO, which merged with Williams in April 1998. She began her career with Cities Service Company in 1976.

Ralph A. Hill . . . . Senior Vice President, Exploration & Production
Age: 50

Position held since December 1998.

Mr. Hill acts as President of our Exploration & Production business unit. He was Vice President of the Exploration & Production business from 1993 to 1998 as well as Senior Vice President Petroleum Services from 1998 to 2003. Mr. Hill serves as a director of Apco Oil and Gas International Inc.

Steven J. Malcolm . . . . Chairman of the Board, Chief Executive Officer and President
Age: 61

Position held since September 2001.

Mr. Malcolm became Chairman of the Board in May 2002, Chief Executive Officer in January 2002, and President in September 2001. He was Chief Operating Officer from September 2001 to January 2002 and an Executive Vice President from May 2001 to September 2001. Mr. Malcolm was President and Chief Executive Officer of Williams Energy Services, LLC, a subsidiary of Williams, from 1998 to 2001, and Senior Vice President and General Manager of Williams Field Services Company, a subsidiary of Williams, from 1994 to 1998. Mr. Malcolm is also a director of several entities: Williams Partners GP LLC, the general partner of Williams Partners L.P.; Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P.; BOK Financial Corporation; and Bank of Oklahoma N.A.

Phillip D. Wright . . . . Senior Vice President, Gas Pipeline
Age: 54

Position held since January 2005.

Mr. Wright acts as President of our Gas Pipeline business unit. From October 2002 to January 2005, he served as Chief Restructuring Officer. From September 2001 to October 2002, Mr. Wright served as President and Chief Executive Officer of our subsidiary Williams Energy Services. From 1996 until September 2001, he was Senior Vice President, Enterprise Development and Planning for our energy services group. Mr. Wright serves as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline Partners L.P., and a director and Senior Vice President, Gas Pipeline, of Williams Partners GP LLC, the general partner of Williams Partners L.P.

PART II

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

Our common stock is listed on the New York Stock Exchange under the symbol "WMB." At the close of business on February 19, 2010, we had approximately 10,445 holders of record of our common stock. The high and low closing sales price ranges (New York Stock Exchange composite transactions) and dividends declared by quarter for each of the past two years are as follows:

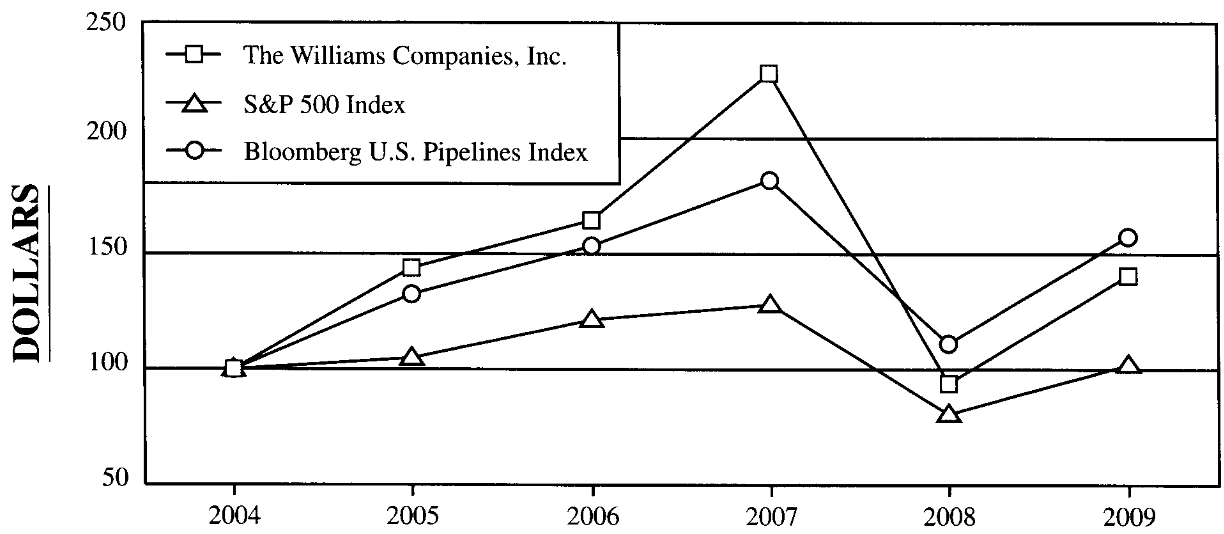
	2009			2008		
Quarter	High	Low	Dividend	High	Low	Dividend
1st	$16.31	$ 9.83	$.11	$36.99	$30.96	$.10
2nd	$17.82	$11.53	$.11	$40.31	$33.65	$.11
3rd	$18.98	$13.83	$.11	$39.90	$21.85	$.11
4th	$21.37	$16.89	$.11	$22.50	$12.13	$.11

Some of our subsidiaries' borrowing arrangements limit the transfer of funds to us. These terms have not impeded, nor are they expected to impede, our ability to pay dividends.

Performance Graph

Set forth below is a line graph comparing our cumulative total stockholder return on our common stock (assuming reinvestment of dividends) with the cumulative total return of the S&P 500 Stock Index and the Bloomberg U.S. Pipeline Index for the period of five fiscal years commencing January 1, 2005. The Bloomberg U.S. Pipeline Index is composed of Enbridge Inc., Spectra Energy Corp, TransCanada Corporation, and The Williams Companies, Inc. The graph below assumes an investment of $100 at the beginning of the period.

Cumulative Total Shareholder Return



	2004	2005	2006	2007	2008	2009
The Williams Companies, Inc.	100.0	143.9	164.6	228.3	94.0	140.7
S&P 500 Index	100.0	104.9	121.5	128.1	80.7	102.1
Bloomberg U.S. Pipelines Index	100.0	132.5	153.5	182.0	111.2	157.6

Item 6. *Selected Financial Data*

The following financial data at December 31, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, should be read in conjunction with Part II, Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* and Part II, Item 8, *Financial Statements and Supplementary Data* of this Form 10-K. The following financial data at December 31, 2007, 2006, and 2005, and for the years ended December 31, 2006 and 2005, has been prepared from our accounting records.

	2009	2008	2007	2006	2005
		(Millions, except per-share amounts)			
Revenues(1)	$ 8,255	$11,890	$10,239	$ 9,144	$ 9,537
Income from continuing operations(2)	584	1,467	910	366	458
Income (loss) from discontinued operations(3)	(223)	125	170	(17)	(116)
Cumulative effect of change in accounting principle(4)	—	—	—	—	(2)
Amounts attributable to The Williams Companies, Inc.:					
Income from continuing operations	438	1,306	829	332	446
Income (loss) from discontinued operations	(153)	112	161	(23)	(130)
Cumulative effect of change in accounting principle	—	—	—	—	(2)
Diluted earnings (loss) per common share:					
Income from continuing operations	.75	2.21	1.37	.55	.75
Income (loss) from discontinued operations	(.26)	.19	.26	(.04)	(.22)
Total assets at December 31	25,280	26,006	25,061	25,402	29,443
Short-term notes payable and long-term debt due within one year at December 31	17	18	108	358	88
Long-term debt at December 31	8,259	7,683	7,580	7,410	7,344
Stockholders' equity at December 31	8,447	8,440	6,375	6,073	5,427
Cash dividends declared per common share	.44	.43	.39	.345	.25

(1) Amounts for 2008 and 2007 have been adjusted to reflect the presentation of certain revenues and costs for Midstream on a net basis. These adjustments reduced previously reported *revenues* and *costs and operating expenses* by the same amounts, with no impact to segment profit. The reductions were $295 million in 2008 and $99 million in 2007.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales, impairments, and other accruals in 2009, 2008, and 2007. Income from continuing operations for 2006 includes a $73 million charge for a litigation contingency. Income from continuing operations for 2005 includes an $82 million charge for litigation contingencies and a $110 million charge for impairments of certain equity investments.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2009, 2008, and 2007 income (loss) from discontinued operations. The discontinued operations results for 2006 includes our former power business, discontinued Venezuela operations, as well as amounts associated with our former chemical fertilizer business, a former exploration business, our former Alaska refinery, and our former distributive power business. The discontinued operations results for 2005 includes our former power business and discontinued Venezuela operations.

(4) The 2005 *cumulative effect of change in accounting principle* is due to the implementation of Financial Accounting Standards Board (FASB) Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations — an Interpretation of FASB statement No. 143 (SFAS No. 143)."

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

Strategic Restructuring

On February 17, 2010, we completed a strategic restructuring, which involved contributing a substantial majority of our domestic midstream and gas pipeline businesses, including our limited- and general-partner interests in Williams Pipeline Partners L.P. (WMZ), into Williams Partners L.P. (WPZ). As consideration for the asset contributions, we received proceeds from WPZ's debt issuance of approximately $3.5 billion, less WPZ's transaction fees and expenses, as well as 203 million WPZ Class C units, which are identical to common units, except for a prorated initial distribution. We also maintained our 2 percent general-partner interest. WPZ assumed approximately $2 billion of existing debt associated with the gas pipeline assets. In connection with the restructuring, we retired $3 billion of our debt and paid $574 million in related premiums. These amounts, as well as other transaction costs, were primarily funded with the cash consideration received from WPZ. The premiums paid and certain other transaction costs will be recorded as expense in the first quarter of 2010. As a result of our restructuring, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions. (See Note 19 of Notes to Consolidated Financial Statements.)

In conjunction with the restructuring, WPZ intends to make an exchange offer for the publicly held units of WMZ at a future date. See "Strategic Restructuring" in Part I, Item 1 of this Form 10-K for further discussion of this potential exchange offer.

Beginning with reporting of first-quarter 2010 results, we will change our segment reporting structure to align with the new parent-level focus, resource allocation management and related governance provisions resulting from the restructuring. Our reporting segments will be Williams Partners, Exploration & Production, and Other. Exploration & Production will include our current Gas Marketing segment and Other will include certain midstream and gas pipeline businesses that were not contributed to WPZ, such as our Canadian and olefins midstream businesses and the remaining 25.5 percent interest in Gulfstream, as well as corporate operations.

Information in this report has generally been prepared to be consistent with the reportable segment presentation in our consolidated financial statements in Part II, Item 8 of this document, which reflects our segment reporting structure prior to the restructuring.

General

We are primarily a natural gas company engaged in finding, producing, gathering, processing, and transporting natural gas. Our operations are located principally in the United States and are organized into the following reporting segments as of December 31, 2009: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids, and Gas Marketing Services. (See Note 1 of Notes to Consolidated Financial Statements and Part I Item 1 for further discussion of these segments.)

Unless indicated otherwise, the following discussion and analysis of critical accounting estimates, results of operations, and financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Part II, Item 8 of this document.

Overview of 2009

The overall economic recession, related lower energy commodity price environment, and challenging financial markets during the past year had a significant impact on our business. While we began to see improvement in the second half of the year, these conditions have resulted in sharply lower results of operations, cash flow from operations and capital expenditures in 2009 compared to 2008. Anticipating these circumstances, our plan for 2009 was built around the transition from significant growth to a focus on sustaining our current operations and reducing costs where appropriate. Although capital expenditures were reduced compared to the prior year, we continued to invest in our businesses with a focus on completing major projects, meeting legal, regulatory, and/or contractual commitments, and maintaining a reduced level of natural gas production development. Objectives and highlights of this plan included:

Objectives	Highlights
Continuing to invest in our gathering and processing and interstate natural gas pipeline systems	We invested $513 million in capital expenditures in Midstream, primarily Deepwater Gulf expansion projects and gas-processing capacity in the western United States. We also invested $485 million in capital expenditures in Gas Pipeline during 2009.
Continuing to invest in our natural gas production development, although at a lower level than in recent years	We invested $1.3 billion in drilling activity and the acquisition of additional producing properties in Exploration & Production.
Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions, as well as seizing attractive opportunities	During 2009, capital and investment purchases were funded primarily through cash flow from operations while maintaining liquidity of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities. In addition, our Exploration & Production and Midstream segments seized growth opportunities to enter the Marcellus Shale, while Exploration & Production also expanded its footprint in the Piceance basin. (See further discussion in Other Significant 2009 Events.)

Our 2009 *income from continuing operations* attributable to The Williams Companies, Inc., decreased by $868 million compared to 2008. This decrease is primarily reflective of the overall unfavorable commodity price environment for the full year of 2009 as compared to 2008. Commodity prices declined sharply in the fourth quarter of 2008, but have improved in the latter half of 2009. See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for 2009 decreased $783 million compared to 2008, primarily due to the decrease in our operating results. See additional discussion in Management's Discussion and Analysis of Financial Condition and Liquidity.

Other Significant 2009 Events

In March 2009, we issued $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to certain institutional investors in a private debt placement. In August 2009, we completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In April 2009, Midstream announced its plan to build a 261-mile natural gas liquids pipeline in Canada at an estimated cost of $283 million. Construction is expected to begin in 2010 with completion expected in 2012.

In May 2009, certain of Midstream's Venezuela operations were expropriated by the Venezuelan government. As a result, these operations are now reflected as discontinued operations and have been deconsolidated. (See Note 2 of Notes to Consolidated Financial Statements.)

In June 2009, Midstream finalized the formation of a new joint venture in the Marcellus Shale located in southwest Pennsylvania. (See Results of Operations — Segments, Midstream Gas & Liquids.)

In June 2009, Exploration & Production entered into an agreement to develop properties in the Marcellus Shale. (See Results of Operations — Segments, Exploration & Production.)

In September 2009, Exploration & Production completed the purchase of additional properties in the Piceance basin of Colorado for $253 million. (See Results of Operations — Segments, Exploration & Production.)

In September 2009, Gas Pipeline received approval from the FERC to begin construction of the 85 North expansion project at an estimated cost of $241 million. (See Results of Operations — Segments, Gas Pipeline.)

Outlook for 2010

We believe we are well positioned to execute on our 2010 business plan and to capture attractive growth opportunities. The economic environment in the latter half of 2009 has improved compared to conditions earlier in the year. In addition, economic and commodity price indicators for 2010 and beyond reflect continued improvement in the economic environment. However, given the potential volatility of these measures, it is reasonably possible that the economy could worsen and/or commodity prices could decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of goodwill and long-lived assets.

As a result of our 2010 restructuring, as previously discussed, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

We continue to operate with a focus on EVA® and invest in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering and processing and interstate natural gas pipeline systems;
- Continuing to invest in our natural gas drilling at a level generally consistent with the prior year and maintaining capacity to consider additional investment in attractive opportunities to diversify our reserves;
- Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions.

Potential risks and/or obstacles that could impact the execution of our plan include:

- Lower than anticipated commodity prices;
- Lower than expected levels of cash flow from operations;
- Availability of capital;
- Counterparty credit and performance risk;
- Decreased drilling success at Exploration & Production;
- Decreased volumes from third parties served by Midstream;
- General economic, financial markets, or industry downturn;
- Changes in the political and regulatory environments;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate insurance policy limit is $37.5 million in the event of a material loss.

We continue to address these risks through utilization of commodity hedging strategies, disciplined investment strategies, and maintaining at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Accounting Pronouncements Issued But Not Yet Adopted

Accounting pronouncements that have been issued but not yet adopted may have an effect on our Consolidated Financial Statements in the future.

See *Accounting Standards Issued But Not Yet Adopted* in Note 1 of Notes to Consolidated Financial Statements for further information on recently issued accounting standards.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions. We have discussed the following accounting estimates and assumptions as well as related disclosures with our Audit Committee. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, or the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

Impairments of Long-Lived Assets and Goodwill

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that may include the estimated fair value of the asset, undiscounted future cash flows, discounted future cash flows, and the current and future economic environment in which the asset is operated.

We assess our natural gas-producing properties and associated unproved leasehold costs for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. Considering market-based pricing at December 31, 2009, we are not currently aware of any significant properties that are approaching impairment thresholds.

In addition to those long-lived assets for which impairment charges were recorded (see Note 4 of Notes to Consolidated Financial Statements), certain others were reviewed for which no impairment was required. These reviews included Exploration & Production's properties and utilized inputs consistent with those described above. Certain assets within our Midstream segment were also evaluated for impairment utilizing judgments and assumptions including future fees, margins, and volumes. These underlying variables are subjective and susceptible to change. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

We have goodwill of approximately $1 billion at Exploration & Production related to its domestic operations (the reporting unit) primarily resulting from a 2001 acquisition. We assess goodwill for impairment annually as of the end of the year. Because quoted market prices are not available for the reporting unit, management applies a range of reasonable judgments (including market supported assumptions when available) in estimating a range of fair values for the reporting unit.

We estimate the fair value of the reporting unit on a stand-alone basis and also consider our market capitalization in corroborating our estimate of the fair value of the reporting unit. As of December 31, 2009, the estimated fair value of the reporting unit exceeds its carrying value, including goodwill, indicating no impairment of Exploration & Production's goodwill.

We estimated the fair value of the reporting unit on a stand-alone basis primarily by valuing proved and unproved reserves. We used an income approach (discounted cash flows) for valuing reserves. The significant inputs into the valuation of proved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, and appropriate discount rates. Unproved reserves were valued using similar assumptions adjusted further for the uncertainty associated with these reserves. We corroborated our fair value estimates with recent market transactions where possible.

In estimating the inputs, management must make assumptions that require judgments and are subject to change in response to changing market conditions and other future events. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.7 Tcfe, forward natural gas prices, adjusted for locational differences, averaging approximately $5.97 per Mcfe, and an after-tax discount rate of 11 percent.

At December 31, 2009, we believe that an overall 20 percent or greater reduction to our estimates of future revenues, which are a component of our estimates of future cash flows, could result in an impairment of goodwill. Future revenue estimates are largely impacted by estimated prices and reserves. This sensitivity does not include any related changes in operating taxes or production costs. We currently do not consider such a decrease in future revenues across all future periods to be likely.

We further reviewed the fair value of the reporting unit estimated on a stand-alone basis, by considering our market capitalization in a reconciliation of the fair values of all our businesses, including the reporting unit. In this reconciliation, we determined our market capitalization, including a control premium, and estimated the fair values of all our businesses considering certain financial performance metrics. The range of control premiums that we considered were consistent with historical market sales transactions and also considered the current market environment. Market capitalization was based on our traded stock price for a reasonably short period of time before and after December 31, 2009. In evaluating the items in our reconciliation analysis, management considered a range of reasonable judgments. This analysis allowed management to consider market expectations in corroborating the reasonableness of the estimated fair value of the reporting unit.

We also perform interim assessments of goodwill if impairment triggering events or circumstances are present. Examples of impairment triggering events or circumstances include:

- The testing for recoverability of a significant long-lived asset group within the reporting unit;
- Sustained operating losses or negative cash flows at the reporting unit level;
- A significant decline in forward natural gas prices or reserve quantities;
- Not meeting internal forecasts, or significant downward adjustments to future forecasts;
- A decline in enterprise market capitalization below our total consolidated stockholders' equity;
- Industry trends.

We cannot predict future market conditions and events that might adversely affect the estimated fair value of the Exploration & Production reporting unit and possibly the reported value of goodwill. The estimated fair value of the reporting unit is significantly affected by natural gas prices, reserve quantities, and market expectations for required rates of return. There are numerous uncertainties inherent in estimating quantities of reserves that could affect our reserve quantities. Low prices for natural gas, regulatory limitations, or the lack of available capital for projects could adversely affect the development and production of additional reserves. Given the challenges affecting our businesses and the energy industry in 2010, these factors could impact us and require us to perform interim assessments of goodwill for possible impairment during 2010, which could result in a material impairment of our goodwill.

Accounting for Derivative Instruments and Hedging Activities

We review our energy contracts to determine whether they are, or contain derivatives. We further assess the appropriate accounting method for any derivatives identified, which could include:

- Qualifying for and electing cash flow hedge accounting, which recognizes changes in the fair value of the derivative in other comprehensive income (to the extent the hedge is effective) until the hedged item is recognized in earnings;
- Qualifying for and electing accrual accounting under the normal purchases and normal sales exception; or
- Applying mark-to-market accounting, which recognizes changes in the fair value of the derivative in earnings.

If cash flow hedge accounting or accrual accounting is not applied, a derivative is subject to mark-to-market accounting. Determination of the accounting method involves significant judgments and assumptions, which are further described below.

The determination of whether a derivative contract qualifies as a cash flow hedge includes an analysis of historical market price information to assess whether the derivative is expected to be highly effective in offsetting the cash flows attributed to the hedged risk. We also assess whether the hedged forecasted transaction is probable of occurring. This assessment requires us to exercise judgment and consider a wide variety of factors in addition to our intent, including internal and external forecasts, historical experience, changing market and business conditions, our financial and operational ability to carry out the forecasted transaction, the length of time until the forecasted transaction is projected to occur, and the quantity of the forecasted transaction. In addition, we compare actual cash flows to those that were expected from the underlying risk. If a hedged forecasted transaction is not probable of occurring, or if the derivative contract is not expected to be highly effective, the derivative does not qualify for hedge accounting.

For derivatives designated as cash flow hedges, we must periodically assess whether they continue to qualify for hedge accounting. We prospectively discontinue hedge accounting and recognize future changes in fair value directly in earnings if we no longer expect the hedge to be highly effective, or if we believe that the hedged forecasted transaction is no longer probable of occurring. If the forecasted transaction becomes probable of not occurring, we reclassify amounts previously recorded in other comprehensive income into earnings in addition to prospectively discontinuing hedge accounting. If the effectiveness of the derivative improves and is again expected to be highly effective in offsetting the cash flows attributed to the hedged risk, or if the forecasted transaction again becomes probable, we may prospectively re-designate the derivative as a hedge of the underlying risk.

Derivatives for which the normal purchases and normal sales exception has been elected are accounted for on an accrual basis. In determining whether a derivative is eligible for this exception, we assess whether the contract provides for the purchase or sale of a commodity that will be physically delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In making this assessment, we consider numerous factors, including the quantities provided under the contract in relation to our business needs, delivery locations per the contract in relation to our operating locations, duration of time between entering the contract and delivery, past trends and expected future demand, and our past practices and customs with regard to such contracts. Additionally, we assess whether it is probable that the contract will result in physical delivery of the commodity and not net financial settlement.

Since our energy derivative contracts could be accounted for in three different ways, two of which are elective, our accounting method could be different from that used by another party for a similar transaction. Furthermore, the accounting method may influence the level of volatility in the financial statements associated with changes in the fair value of derivatives, as generally depicted below:

	Consolidated Statement of Income		Consolidated Balance Sheet	
Accounting Method	**Drivers**	**Impact**	**Drivers**	**Impact**
Accrual Accounting	Realizations	Less Volatility	None	No Impact
Cash Flow Hedge Accounting	Realizations & Ineffectiveness	Less Volatility	Fair Value Changes	More Volatility
Mark-to-Market Accounting	Fair Value Changes	More Volatility	Fair Value Changes	More Volatility

Our determination of the accounting method does not impact our cash flows related to derivatives.

Additional discussion of the accounting for energy contracts at fair value is included in Notes 1 and 15 of Notes to Consolidated Financial Statements.

Oil- and Gas-Producing Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates.
- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. This, in turn, can impact our periodic impairment analyses, including that for goodwill.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering, and economic data. After being estimated internally, approximately 99 percent of our reserve estimates are either audited or prepared by independent experts. (See Part I Item 1 for further discussion.) The data may change substantially over time as a result of numerous factors, including additional development cost and activity, evolving production history, and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. Such changes could trigger an impairment of our oil and gas properties and/or goodwill and have an impact on our *depreciation, depletion and amortization* expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual *depreciation, depletion and amortization* expense between approximately \$72 million and \$87 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserve categories.

Forward market prices, which are utilized in our impairment analyses, include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating our drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the forward price curve could result in an impairment of our oil and gas properties and/or goodwill.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including environmental matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers, or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 16 of Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Tax Contingencies

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of the book basis and from tax carry-forwards generated in the current and prior years. We must evaluate whether we will ultimately realize these tax benefits and establish a valuation allowance for those that may not be realizable. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. At December 31, 2009, we have \$681 million of deferred tax assets for which a \$4 million valuation allowance has been established. When assessing the need for a valuation allowance, we consider forecasts of future company performance, the estimated impact of potential asset dispositions, and our ability and intent to execute tax planning strategies to utilize tax carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

We regularly face challenges from domestic and foreign tax authorities regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. We evaluate the liability associated with our various filing positions by applying the two step process of recognition and measurement. The ultimate disposition of these contingencies could have a significant impact on operating results and net cash flows. To the extent we were to prevail in matters for which accruals have been established or were required to pay amounts in excess of our accrued liability, our effective tax rate in a given financial statement period may be materially impacted.

See Note 5 of Notes to Consolidated Financial Statements for additional information.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit expense and obligations for these plans are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates, expected rate of compensation increase, health care cost trend rates, and employee demographics, including retirement age and mortality. These assumptions are reviewed annually and adjustments are made as needed. The assumptions utilized to compute expense and the benefit obligations are shown in Note 7 of Notes to Consolidated Financial Statements.

The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations resulting from a one-percentage-point change in the specified assumption.

	Benefit Expense		Benefit Obligation	
	One-Percentage-Point Increase	One-Percentage-Point Decrease	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(Millions)			
Pension benefits:				
Discount rate	$(9)	$10	$(114)	$135
Expected long-term rate of return on plan assets	(9)	9	—	—
Rate of compensation increase	3	(2)	12	(10)
Other postretirement benefits:				
Discount rate	(2)	3	(30)	36
Expected long-term rate of return on plan assets	(1)	1	—	—
Assumed health care cost trend rate	2	(2)	33	(27)

Our expected long-term rates of return on plan assets, as determined at the beginning of each fiscal year, are based on the average rate of return expected on the funds invested in the plans. We determine our long-term expected rate of return on plan assets using our expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. These capital market expectations are based on a long-term period of at least ten years and consider our investment strategy and mix of assets, which is weighted toward domestic and international equity securities. We develop our expectations using input from several external sources, including consultation with our third-party independent investment consultant. The forward-looking capital market projections are developed using a consensus of economists' expectations for inflation, GDP growth, and dividend yield along with expected changes in risk premiums. The capital market return projections for specific asset classes in the investment portfolio are then applied to the relative weightings of the asset classes in the investment portfolio. The resulting rate is an estimate of future results and, thus, likely to be different than actual results.

The capital markets improved in 2009 and the benefit plans' assets reflect this improvement. While the 2009 investment performance was greater than our expected rates of return, the expected rates of return on plan assets are long-term in nature and are not significantly impacted by short-term market performance. Changes to our asset allocation would also impact these expected rates of return. Our expected long-term rate of return on plan assets used for our pension plans has been 7.75 percent since 2006. The 2009 actual return on plan assets for our pension plans was a gain of approximately 21.8 percent. The ten-year average rate of return on pension plan assets through December 2009 was approximately 2.2 percent and is largely affected by the approximately 34.1 percent loss experienced in 2008.

The discount rates are used to measure the benefit obligations of our pension and other postretirement benefit plans. The objective of the discount rates is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality debt securities, that will provide the necessary cash flows when benefit payments are due. Increases in the discount rates decrease the obligation and, generally, decrease the related expense. The discount rates for our pension and other postretirement benefit plans are determined separately based on an approach specific to our plans and their respective expected benefit cash flows as described in Note 7 of Notes to Consolidated Financial Statements. Our discount rate assumptions are impacted by changes in general economic and market conditions that affect interest rates on long-term high-quality debt securities as well as by the duration of our plans' liabilities.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and expense to increase.

The assumed health care cost trend rates are based on national trend rates adjusted for our actual historical cost rates and plan design. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Fair Value Measurements

Certain of our energy derivative assets and liabilities and other assets trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At December 31, 2009, less than 1 percent of the total assets and total liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2009, the credit reserve is less than $1 million on our net derivative assets and $3 million on our net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2009, 82 percent of our derivatives portfolio expires in the next 12 months and more than 99 percent of our derivatives portfolio expires in the next 36 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

At December 31, 2009, Level 2 includes option contracts that hedge future sales of production from our Exploration & Production segment; these options are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Prior to the third quarter of 2009, these options were included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. However, due to the increased transparency, we now consider this input to be observable and have included these options in Level 2.

The instruments included in Level 3 at December 31, 2009, consist of natural gas liquids swaps for our Midstream segment as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production and Midstream segments. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

Exploration & Production has an unsecured credit agreement through December 2013 with certain banks that, so long as certain conditions are met, serves to reduce our usage of cash and other credit facilities for margin requirements related to instruments included in the facility.

For the year ended December 31, 2009, we have recognized impairments of certain assets that have been measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. (See Note 14 of notes to Consolidated Financial Statements.)

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2009. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2009	$ Change from 2008*	% Change from 2008*	2008	$ Change from 2007*	% Change from 2007*	2007
				(Millions)			
Revenues	$8,255	−3,635	−31%	$11,890	+1,651	+16%	$10,239
Costs and expenses:							
Costs and operating expenses	6,081	+2,695	+31%	8,776	−944	−12%	7,832
Selling, general and administrative expenses	512	−8	−2%	504	−43	−9%	461
Other (income) expense — net	17	−89	NM	(72)	+70	NM	(2)
General corporate expenses	164	−15	−10%	149	+12	+7%	161
Total costs and expenses	6,774			9,357			8,452
Operating income	1,481			2,533			1,787
Interest accrued — net	(585)	−8	−1%	(577)	+55	+9%	(632)
Investing income	46	−143	−76%	189	−63	−25%	252
Early debt retirement costs	(1)	—	—	(1)	+18	+95%	(19)
Other income — net	2	+2	NM	—	−12	−100%	12
Income from continuing operations before income taxes	943			2,144			1,400
Provision for income taxes	359	+318	+47%	677	−187	−38%	490
Income from continuing operations	584			1,467			910
Income (loss) from discontinued operations	(223)	−348	NM	125	−45	−26%	170
Net income	361			1,592			1,080
Less: Net income attributable to noncontrolling interests	76	+98	+56%	174	−84	−93%	90
Net income attributable to The Williams Companies, Inc.	$ 285			$ 1,418			$ 990

* + = Favorable change; − = Unfavorable change; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator, or a percentage change greater than 200.

2009 vs. 2008

Our consolidated results in 2009 declined significantly compared to 2008. These results reflect a rapid decline in energy commodity prices that began in the fourth quarter of 2008 as a result of the weakened economy. Energy commodity prices have generally improved during 2009, but not to levels experienced early in 2008.

The decrease in *revenues* is primarily due to decreased realized revenue at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as lower natural gas liquid (NGL) and olefin production revenues and lower marketing revenues at Midstream. In addition, Exploration & Production revenues decreased primarily due to lower net realized average prices, partially offset by higher production volumes sold.

The decrease in *costs and operating expenses* is primarily due to decreased costs at Gas Marketing primarily reflecting a decrease in average natural gas prices as well as decreased marketing purchases and decreased costs associated with our olefin and NGL production businesses at Midstream.

Other (income) expense — net within *operating income* in 2009 includes:

- Gain of $40 million on the sale of our Cameron Meadows NGL processing plant at Midstream;
- Expense of $32 million related to penalties from the early termination of certain drilling rig contracts at Exploration & Production;
- Impairment charges totaling $20 million at Exploration & Production.

Other (income) expense — net within *operating income* in 2008 includes:

- Gain of $148 million on the sale of our Peru interests at Exploration & Production;
- Net gains of $39 million on foreign currency exchanges at Midstream;
- Income of $32 million related to the partial settlement of our Gulf Liquids litigation at Midstream;
- Gain of $10 million on the sale of certain south Texas assets at Gas Pipeline;
- Income of $17 million resulting from involuntary conversion gains at Midstream;
- Impairment charges totaling $143 million related to certain natural gas producing properties at Exploration & Production;
- Expense of $23 million related to project development costs at Gas Pipeline.

General corporate expenses increased primarily due to an increase in employee-related expenses, partially offset by a decrease in outside services.

The decrease in *operating income* generally reflects an overall unfavorable energy commodity price environment in 2009 compared to 2008 and other changes as previously discussed.

The decrease in *investing income* is primarily due to a $75 million impairment of Midstream's Accroven investment and an $11 million impairment of a cost-based investment at Exploration & Production. (See Note 3 of Notes to Consolidated Financial Statements.) A decrease in interest income, primarily due to lower average interest rates in 2009 compared to 2008, also contributed to the decrease in *investing income.*

Provision for income taxes decreased primarily due to lower pre-tax income. See Note 5 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rates compared to the federal statutory rate for both years.

See Note 2 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Net income attributable to noncontrolling interests decreased reflecting the first-quarter 2009 impairments and related charges associated with Midstream's discontinued Venezuela operations (see Note 2 of Notes to Consolidated Financial Statements) and the decline in Williams Partners L.P.'s operating results primarily driven by lower NGL margins.

2008 vs. 2007

Our consolidated results in 2008 improved significantly compared to 2007. However, these results were considerably influenced by favorable results in the first three quarters of the year, followed by a sharp decline in the fourth quarter due to a rapid decline in energy commodity prices.

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production resulting from both higher net realized average prices and increased production volumes sold. Midstream also experienced higher olefin production revenues primarily due to higher average prices and volumes as well as increased NGL production revenues resulting from higher average prices, partially offset by lower volumes. Additionally, Gas Marketing revenues increased primarily due to favorable price movements on derivative positions economically hedging the anticipated withdrawals of natural gas from storage and the absence of a loss recognized on a legacy derivative sales contract in 2007.

The increase in *costs and operating expenses* is primarily due to increased costs associated with our olefin and NGL production businesses at Midstream. Higher depreciation, depletion, and amortization and higher operating taxes at Exploration & Production also contributed to the increase in expenses.

The increase in *selling, general and administrative expenses (SG&A)* primarily includes the impact of higher staffing and compensation at our Exploration & Production and Midstream segments in support of increased operational activities.

Other (income) expense — net within *operating income* in 2007 includes:

- Income of $18 million associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral;
- Income of $17 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline;
- Income of $12 million related to a favorable litigation outcome at Midstream;
- Income of $8 million due to the reversal of a planned major maintenance accrual at Midstream;
- Expense of $20 million related to an accrual for litigation contingencies at Gas Marketing;
- Net losses of $11 million on foreign currency exchanges at Midstream;
- Expense of $10 million related to an impairment of the Carbonate Trend pipeline at Midstream.

The increase in *operating income* reflects improved operating results at Exploration & Production due to higher net realized average prices, natural gas production growth and a gain of $148 million on the sale of our Peru interests, partially offset by increased operating costs and $143 million of property impairments in 2008. The increase also reflects improved results at Gas Marketing primarily due to favorable price movements on derivative positions economically hedging the anticipated withdrawals of natural gas from storage and the absence of a loss recognized on a legacy derivative sales contract in 2007. Partially offsetting these increases is a decrease in *operating income* at Midstream primarily due to a sharp decline in energy commodity prices in the latter part of 2008.

Interest accrued — net decreased primarily due to increased capitalized interest resulting from an increased level of capital expenditures. The decrease was also a result of lower interest rates on debt issuances that occurred late in the fourth quarter of 2007 and in the first half of 2008 for which the proceeds were primarily used to retire existing debt bearing higher interest rates. While our overall debt balances have been relatively comparable, the net effect of these retirements and issuances has resulted in lower rates.

The decrease in *investing income* is primarily due to a decrease in interest income largely resulting from lower average interest rates in 2008 compared to 2007.

Early debt retirement costs in 2007 includes $19 million of premiums and fees related to the December 2007 repurchase of senior unsecured notes.

Provision for income taxes increased primarily due to higher pre-tax income partially offset by a reduction in our estimate of the effective deferred state tax rate in 2008. See Note 5 of Notes to Consolidated Financial Statements for a reconciliation of the effective tax rate compared to the federal statutory rate for both years.

See Note 2 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Net income attributable to noncontrolling interests increased primarily reflecting the growth in the noncontrolling interest holdings of Williams Partners L.P. and Williams Pipeline Partners L.P. in late 2007 and early 2008, respectively.

Results of Operations — Segments

As of December 31, 2009, we are organized into the following segments: Exploration & Production, Gas Pipeline, Midstream, Gas Marketing Services, and Other. Other primarily consists of corporate operations. Our management evaluates performance based on segment profit (loss) from operations. (See Note 18 of Notes to Consolidated Financial Statements.)

As previously discussed, our reportable segments will change in the first quarter of 2010 as a result of our restructuring transactions.

Exploration & Production

Overview of 2009

Segment revenues and segment profit for 2009 were significantly lower than 2008 primarily due to a sharp decline in net realized average prices partially offset by higher production volumes. Additionally, 2009 results include expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts and $20 million of impairment charges. Highlights of the comparative periods include:

	For The Years Ended December 31,		
	2009	2008	% Change
Average daily domestic production sold (MMcfe)(1)	1,182	1,094	+8%
Average daily total production sold (MMcfe)	1,236	1,144	+8%
Domestic net realized average price ($/Mcfe)(2)	$ 4.22	$ 6.48	−35%
Capital expenditures incurred ($ millions)	$1,291	$2,519	−49%
Segment revenues ($ millions)	$2,219	$3,121	−29%
Segment profit ($ millions)	$ 418	$1,260	−67%

(1) MMcfe is equal to one million cubic feet of gas equivalent.

(2) Mcfe is equal to one thousand cubic feet of gas equivalent.

- The increased production is primarily within the Piceance, Powder River, and Fort Worth basins. We reduced development activities and related capital expenditures in 2009, which resulted in production peaking during the first quarter of 2009, then decreasing slightly thereafter.
- Net realized average prices include market prices, net of fuel and shrink and hedge gains and losses, less gathering and transportation expenses. The realized hedge gain per Mcfe was $1.43 and $.09 for 2009 and 2008, respectively.

We drilled 875 gross domestic productive development wells in 2009 with a success rate of 99 percent. On January 14, 2009, the SEC issued the *Final Rule for Modernization of Oil and Gas Reporting* which affects how oil and gas companies report their reserves. These changes included: (1) applying the expanded definition of oil and gas reserves used for reserves estimation supported by reliable technologies and reasonable certainty; (2) revising proved undeveloped reserve estimates based on new guidance; and (3) estimating proved reserves for disclosure in SEC filings using the 12-month average, first-of-the-month price instead of a single-day, period-end price. The FASB substantially conformed its requirements to the SEC rule with the issuance of its Accounting Standards Update 2010-03, *Oil and Gas Reserve Estimation and Disclosures*. Our estimated domestic proved reserves as of December 31, 2009 are 4,255 Bcfe.

Significant Events

In June 2009, we entered into an agreement that allows us to acquire, through a "drill to earn" structure, a 50 percent interest in approximately 44,000 net acres in Pennsylvania's Marcellus Shale in the Appalachian basin. This agreement requires us to fund $33 million of drilling and completion costs on behalf of our partner and $41 million of our own costs and expenses prior to the end of 2011 to earn our 50 percent interest. This growth opportunity leverages our experience in developing nonconventional natural gas reserves. Through December 2009, we have funded $14 million of the $33 million.

In September 2009, we completed the purchase of additional unproved leasehold acreage and proved properties in the Piceance basin for $253 million. In December 2009, we increased our working interest in these properties through a $22 million acquisition.

Outlook for 2010

We expect natural gas prices to increase in 2010, resulting in higher segment revenues and segment profit. We plan to maintain capital expenditures at a level similar to 2009 with a consistent level of drilling rigs operating in 2010 compared to 2009. We have the following expectations and objectives for 2010:

- Continuation of our development drilling program in the Piceance, Fort Worth, Powder River, San Juan and Appalachian basins. Our capital expenditures for 2010 are projected to be between $1 billion and $1.4 billion. This includes our drilling program in the Marcellus Shale that will enable us to meet the terms of our agreement as previously discussed.
- Annual average daily domestic production level consistent with 2009, with fourth quarter 2010 volumes likely to be higher than the prior year comparable period.
- Stability in the costs of services and materials associated with development activities.

Risks to achieving our expectations and objectives include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production levels and demand, and a slower recovery in the global economy than expected. A significant decline in natural gas prices could impact these expectations for 2010, although the impact would be somewhat mitigated by our hedging program, which hedges a significant portion of our expected production.

In addition, changes in laws and regulations may impact our development drilling program. For example, the Colorado Oil & Gas Conservation Commission enacted new rules effective in April 2009 which increased our costs of permitting and environmental compliance and could potentially delay drilling permits. The new rules included additional environmental and operational requirements as part of permit approvals, tracking of certain chemicals brought on location, increased wildlife stipulations, new pit and waste management procedures and increased notifications and approvals from surface landowners. Our current outlook incorporates these changes; however, the extent and magnitude of other changes in laws and regulations could be greater than our current assumptions.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our future production. For 2010, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

	2010	
	Volume (MMcf/d)	**Price ($/Mcf) Floor-Ceiling for Collars**
Collars — Rockies	100	$6.53 - $8.94
Collars — San Juan	233	$5.75 - $7.82
Collars — Mid-Continent	105	$5.37 - $7.41
Collars — Southern California	45	$4.80 - $6.43
Collars — Other	28	$5.63 - $6.87
NYMEX and basis fixed-price	120	$4.40

The following is a summary of our contracts for daily production for the years ended December 31, 2009, 2008 and 2007:

	2009		2008		2007	
	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collars — NYMEX	—	—	—	—	15	$6.50 - $8.25
Collars — Rockies	150	$6.11 - $9.04	170	$6.16 - $9.14	50	$5.65 - $7.45
Collars — San Juan	245	$6.58 - $9.62	202	$6.35 - $8.96	130	$5.98 - $9.63
Collars — Mid-Continent	95	$7.08 - $9.73	63	$7.02 - $9.72	76	$6.82 - $10.77
NYMEX and basis fixed-price	106	$3.67	70	$3.97	172	$3.90

Additionally, we utilize contracted pipeline capacity through Gas Marketing Services to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We hold a long-term obligation through Gas Marketing Services to deliver on a firm basis 200,000 MMbtu per day of gas to a buyer at the White River Hub (Greasewood-Meeker, Colorado), which is the major market hub exiting the Piceance basin. Our interest in the Piceance basin holds ample reserves to meet this obligation.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Segment revenues	$2,219	$3,121	$2,021
Segment profit	$ 418	$1,260	$ 756

2009 vs. 2008

The decrease in total *segment revenues* is primarily due to the following:

- $725 million, or 27 percent, decrease in domestic production revenues reflecting $935 million associated with a 35 percent decrease in net realized average prices, partially offset by an increase of $210 million associated with a 8 percent increase in production volumes sold. Production revenues in 2009 and 2008 include approximately $93 million and $85 million, respectively, related to natural gas liquids (NGL) and approximately $36 million and $62 million, respectively, related to condensate. While NGL volumes were significantly higher than the prior year, NGL prices were significantly lower.

- $169 million decrease primarily reflecting lower average sales prices for gas management activities related to gas purchased from certain outside parties, which is offset by a similar decrease in *segment costs and expenses.*

Total *segment costs and expenses* decreased $62 million, primarily due to the following:

- $163 million lower operating taxes due primarily to 56 percent lower average market prices (excluding the impact of hedges), partially offset by higher production volumes sold. The lower operating taxes include a net decrease of $39 million reflecting a $34 million charge in 2008 and $5 million of favorable revisions in 2009 relating to Wyoming severance and ad valorem tax issues;

- $165 million decrease primarily reflecting lower average sales prices for gas management activities related to gas purchased from certain outside parties, which is offset by a similar decrease in *segment revenues*;

- $143 million due to the absence of property impairments recorded in 2008 in the Arkoma basin;

- $8 million lower lease and other operating expenses due to lower industry costs and activity partially offset by the effect of an increase in production volumes;

- $5 million lower SG&A expenses, which includes lower bad debt expense related to the partial recovery of certain receivables previously reserved for in 2008 resulting from a bankrupt counterparty.

Partially offsetting the decreased costs are increases due to the following:

- The absence of a $148 million gain recorded in 2008 associated with the sale of our Peru interests;
- $152 million higher depreciation, depletion and amortization expense primarily due to the impact of higher capitalized drilling costs from prior years and higher production volumes compared to the prior year. Also, we recorded an additional $17 million of depreciation, depletion, and amortization in the fourth quarter of 2009 primarily due to new SEC reserves reporting rules. Our proved reserves decreased primarily due to the new SEC reserves reporting rules and the related price impact;
- $48 million higher gathering fees primarily due to higher production volumes and the processing fees for natural gas liquids at Midstream's Willow Creek plant, which began processing in August 2009;
- $32 million of expense related to penalties from the early release of drilling rigs as previously discussed;
- $20 million of impairment costs in the Fort Worth and Arkoma basins. We recorded a $15 million impairment in 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth basin. This impairment was based on our assessment of estimated future discounted cash flows and additional information obtained from drilling and other activities in 2009. We also recorded a $5 million impairment in the Arkoma basin in 2009 related to facilities;
- $31 million higher exploratory expense in 2009, primarily related to $20 million of increased seismic costs and $12 million related to higher amortization and the write-off of lease acquisition costs. Dry hole costs for 2009 and 2008 were $11 million and $12 million, respectively. As of December 31, 2009 we have approximately $14 million of capitalized drilling costs and $24 million of undeveloped leasehold costs related to continuing exploratory activities in the Paradox basin.

The $842 million decrease in *segment profit* is primarily due to the 35 percent decrease in net realized average domestic prices and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

2008 vs. 2007

The increase in total *segment revenues* is primarily due to the following:

- $919 million, or 53 percent, increase in domestic production revenues reflecting $571 million associated with a 28 percent increase in net realized average prices and $348 million associated with a 20 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the effect of fewer volumes hedged by fixed-price contracts. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in 2008 and 2007 include approximately $85 million and $53 million, respectively, related to natural gas liquids and approximately $62 million and $40 million, respectively, related to condensate.
- $151 million increase in revenues for gas management activities related to gas purchased from certain outside parties, which is substantially offset by a similar increase in *segment costs and expenses*. This increase is primarily due to increases in natural gas prices and volumes sold.
- $17 million favorable change related to hedge ineffectiveness due to $1 million in net unrealized gains from hedge ineffectiveness in 2008 compared to $16 million in net unrealized losses in 2007.

Total *segment costs and expenses* increased $591 million, primarily due to the following:

- $202 million higher depreciation, depletion and amortization expense, primarily due to higher production volumes and increased capitalized drilling costs.
- $149 million increase in expenses for gas management activities related to gas purchased from certain outside parties, which is offset by a similar increase in *segment revenues*.

- $143 million of property impairments in 2008 in the Arkoma basin.
- $118 million higher operating taxes primarily due to both higher average market prices and higher domestic production volumes sold and the $34 million charge related to the Wyoming severance and ad valorem tax issue.
- $61 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins combined with increased prices for well and lease service expenses and higher facility expenses.
- $28 million higher SG&A expenses primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. The higher SG&A expenses also include an increase of $11 million in bad debt expense.
- $17 million higher gathering expenses due to higher domestic production volumes.
- $17 million of expense in 2008 related to the write-off of certain exploratory drilling costs for our domestic and international operations.

These increases are partially offset by the $148 million gain associated with the sale of our Peru interests in 2008.

The $504 million increase in *segment profit* is primarily due to the 28 percent increase in domestic net realized average prices and the 20 percent increase in domestic production volumes sold, partially offset by the increase in total *segment costs and expenses.*

Gas Pipeline

Overview

Gas Pipeline's strategy to create value focuses on maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets.

Gas Pipeline's interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's ratemaking process. Changes in commodity prices and volumes transported have little near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Gas Pipeline master limited partnership

At December 31, 2009, we own approximately 47.7 percent of WMZ, including 100 percent of the general partner, and incentive distribution rights. Considering the presumption of control of the general partner, we consolidate WMZ within our Gas Pipeline segment. Gas Pipeline's segment profit includes 100 percent of WMZ's segment profit. As previously discussed, our ownership in WMZ was affected by our 2010 restructuring transactions.

Significant events of 2009 include:

Completed Expansion Projects

Gulfstream Phase IV

In September 2007, our 50 percent-owned equity investee, Gulfstream, received FERC approval to construct 17.8 miles of 20-inch pipeline and to install a new compressor facility. The pipeline expansion was placed into service in the fourth quarter of 2008, and the compressor facility was placed into service in January 2009. The expansion increased capacity by 155 Mdt/d. Gulfstream's cost of this project is $190 million.

Sentinel

In August 2008, we received FERC approval to construct an expansion in the northeast United States. The cost of the project is estimated to be $229 million. We placed Phase I into service in December 2008 increasing capacity by 40 Mdt/d. Phase II provided an additional 102 Mdt/d and was placed into service in November 2009.

Colorado Hub Connection

In April 2009, we received approval from the FERC to construct a 27-mile pipeline to provide increased access to the Rockies natural gas supplies. Construction began in June 2009 and the project was placed into service in November 2009. We combined lateral capacity with existing mainline capacity to provide approximately 363 Mdt/d of firm transportation from various receipt points for delivery to Ignacio, Colorado. The estimated cost of the project is $60 million.

In-progress Expansion Projects

Mobile Bay South

In May 2009, we received approval from the FERC to construct a compression facility in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $37 million. The estimated project in-service date is May 2010 and will increase capacity by 253 Mdt/d.

85 North

In September 2009, we received approval from the FERC to construct an expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. The cost of the project is estimated to be $241 million. Phase I service is anticipated to begin in July 2010 and will increase capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 218 Mdt/d.

Mobile Bay South II

In November 2009, we filed an application with the FERC to construct additional compression facilities and modifications to existing facilities in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $36 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost $65 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Outlook for 2010

In addition to the various in-progress expansion projects previously discussed, we have several other proposed projects to meet customer demands. Subject to regulatory approvals, construction of some of these projects could begin as early as 2010.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2009	**2008**	**2007**
		(Millions)	
Segment revenues	$1,591	$1,634	$1,610
Segment profit	$ 667	$ 689	$ 673

2009 vs. 2008

Segment revenues decreased primarily due to a $53 million decrease in revenues from lower transportation imbalance settlements in 2009 compared to 2008 (offset in *costs and operating expenses*), partially offset by a $17 million increase in other service revenues and expansion projects placed into service by Transco.

Costs and operating expenses decreased $27 million, or 3 percent, primarily due to a $53 million decrease in costs associated with lower transportation imbalance settlements in 2009 compared to 2008 (offset in *segment revenues*) and $11 million of income from an adjustment of state franchise taxes. Partially offsetting these decreases is a $13 million increase in depreciation expense due primarily to projects placed into service, a $10 million increase in transportation-related fuel expense resulting from less favorable recovery from customers due to pricing differences, and $7 million higher employee-related expenses.

SG&A increased $6 million, or 4 percent, primarily due to an increase in pension expense.

Other (income) expense — net reflects the absence of a $10 million gain on the sale of certain south Texas assets and a $9 million gain on the sale of excess inventory gas, both of which were recorded by Transco in 2008. Partially offsetting these unfavorable changes is $16 million lower project development costs in 2009.

Segment profit decreased primarily due to the previously described changes, partially offset by higher equity earnings from Gulfstream.

2008 vs. 2007

Segment revenues increased primarily due to a $52 million increase in transportation revenues resulting primarily from Transco's new rates, which were approved by the FERC as part of a general rate case and became effective March 2007, and expansion projects that Transco placed into service in the fourth quarter of 2007. In addition, *segment revenues* increased $28 million due to transportation imbalance settlements (offset in *costs and operating expenses*). Partially offsetting these increases is the absence of $59 million associated with a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses decreased $11 million, or 1 percent, primarily due to the absence of $59 million associated with a 2007 sale of excess inventory gas (offset in *segment revenues*). The decrease is partially offset by an increase in costs of $28 million associated with transportation imbalance settlements (offset in *segment revenues*) and higher rental expense related to the Parachute lateral that was transferred to Midstream in December 2007.

Other (income) expense — net changed unfavorably by $31 million primarily due to the absence of $18 million of income recognized in 2007 associated with payments received for a terminated firm transportation agreement on Northwest Pipeline's Grays Harbor lateral and the absence of $17 million of income recorded in 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline. In addition, project development costs were $21 million higher in 2008. Partially offsetting these unfavorable changes is a $10 million gain on the sale of certain south Texas assets, and a $9 million gain on the sale of excess inventory gas, both of which were recorded by Transco in 2008.

The increase in *segment profit* is primarily due to the previously described changes and higher equity earnings from Gulfstream.

Midstream Gas & Liquids

Overview of 2009

Midstream's ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2009 include the following:

Cameron Meadows Plant

In November 2009, we sold our Cameron Meadows plant and recognized a pre-tax gain of $40 million. This plant sustained hurricane damage twice in recent years and is, therefore, considered incongruent with our strategy of providing the most reliable service in the industry.

Willow Creek

The Willow Creek facility in western Colorado began processing natural gas production and extracting NGLs in early August and achieved full processing operations in September. Currently, the 450-million-cubic-feet-per-day (MMcf/d) gas processing plant primarily processes Exploration & Production's wellhead production, has a peak capacity of 30,000 barrels of NGLs per day, and is recovering approximately 20,000 barrels per day. In the current processing arrangement with Exploration & Production, Midstream receives a volumetric-based processing fee and a percent of the NGLs extracted.

Laurel Mountain Midstream, LLC

In June 2009, we completed the formation of a new joint venture in the Marcellus Shale located in southwest Pennsylvania. Our partner in the venture contributed its existing Appalachian basin gathering system, which currently has an average throughput of approximately 100 MMcf/d. In exchange for a 51 percent interest in the venture, we contributed $100 million and issued a $26 million note payable. We account for this investment under the equity method due to the significant participatory rights of our partner such that we do not control the investment. We have transitioned operational control from our partner to us.

Venezuela

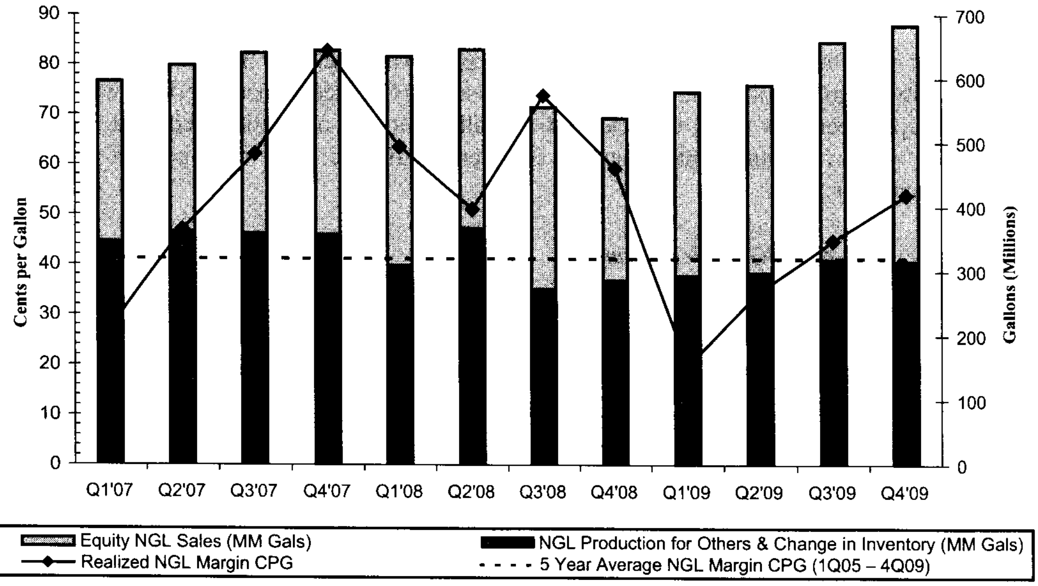
In May 2009, the Venezuelan government expropriated the El Furrial and PIGAP II assets that we operated in Venezuela. As a result, these operations are now reflected as discontinued operations for all periods presented and are no longer included in Midstream's results. Our investment in Accroven, whose assets have not been expropriated, is still included within Midstream and reflects a first-quarter 2009 impairment charge of $75 million. (See Notes 2 and 3 of Notes to Consolidated Financial Statements for further discussion.)

Volatile commodity prices

NGL prices, especially ethane prices, have generally improved during 2009, following significant declines in the fourth quarter of 2008 as a result of the weakened economy. Our NGL margins also benefited from a period of declining natural gas prices during 2009. While average annual per-unit NGL margins in 2009 were still significantly lower than 2008, they improved during 2009 to levels currently above the rolling five-year average per-unit margin. We continued to benefit from favorable natural gas price differentials in the Rocky Mountain area, although the differentials narrowed during 2009. These differentials contributed to realized per-unit margins that were generally greater than that of the industry benchmarks for natural gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

NGL margins are defined as NGL revenues less any applicable BTU replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants.

Domestic Gathering and Processing Per Unit NGL Margin with Production and Sales Volumes by Quarter (excludes partially owned plants)



Hurricane Impact to Insurance Coverage

While our insurance expense has increased modestly in 2009 compared to 2008, the overall level of coverage on our offshore assets in the Gulf Coast region against named windstorm events has substantially decreased, including the absence of coverage on certain of our assets. (See Note 9 of Notes to Consolidated Financial Statements.)

Williams Partners L.P.

As of December 31, 2009, we own approximately 23.6 percent of Williams Partners L.P., including 100 percent of the general partner and incentive distribution rights. Considering the presumption of control of the general partner, we consolidate Williams Partners L.P. within the Midstream segment. (See Note 1 of Notes to Consolidated Financial Statements.) Midstream's segment profit includes 100 percent of Williams Partners L.P.'s segment profit. As previously discussed, our ownership in Williams Partners L.P. and our future segment reporting structure were affected by our 2010 restructuring transactions.

Outlook for 2010

The following factors could impact our business in 2010.

Commodity price changes

- NGL, crude and natural gas prices are highly volatile and difficult to predict. However, we expect per-unit NGL margins in 2010 to be higher than our average per-unit margins in 2009 and our rolling five-year average per-unit NGL margins. NGL, crude and natural gas prices are highly volatile. NGL price changes have historically tracked somewhat with changes in the price of crude oil. Margins in our NGL and olefins business are highly dependent upon continued demand within the global economy. Although forecasted domestic and global demand for polyethylene, or plastics, has been impacted by the weakness in the global economy, NGL products are currently the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene. Propylene and ethylene production processes have increasingly shifted from the more expensive crude-based feedstocks to NGL-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets. As natural gas pipeline transportation capacity increases in the Rocky Mountain area, we anticipate that historically favorable natural gas price differentials will decline.

- In our olefin production business, we anticipate margins in 2010 to show an improvement over 2009, similarly benefiting from the dynamics discussed above.
- As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies. To reduce the exposure to changes in market prices, we have entered into NGL swap agreements to fix the prices of a small portion of our anticipated NGL sales for 2010. In addition, we have entered into financial contracts to fix the price of a portion of our shrink gas requirements for 2010.

Gathering, processing, and NGL sales volumes

- The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. Our customers are generally large producers and we have not experienced and do not anticipate an overall significant decline in volumes due to reduced drilling activity.
- In the West, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in 2010 compared to 2009 as our Willow Creek facility moves into a full year of operation, and our expansion at Echo Springs is completed late in 2010.
- We expect fee revenues, NGL volumes, depreciation expense, and operating expenses in our offshore Gulf Coast region to increase from 2009 levels as our new Perdido Norte expansion begins start-up operations in the first quarter of 2010. Increases from our Perdido Norte expansion are expected to be partially offset by lower volumes in other Gulf Coast areas due to expected changes in gas processing contracts, as described below, and natural declines.
- Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee basis, keep-whole, or percent-of-liquids basis. If customers switch from keep-whole to fee-based processing, this would reduce our NGL equity sales volumes.

Allocation of capital to expansion projects

We expect to spend $500 million to $750 million in 2010 on capital projects. The ongoing major expansion projects include:

- The Perdido Norte project, in the western deepwater of the Gulf of Mexico, which includes an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure. Significant milestones have been reached and, considering the progress of our customer's drilling and tie-in construction, we expect this project to begin start-up operations in the first quarter of 2010.
- Additional processing and NGL production capacities at our Echo Springs facility and related gathering system expansions in the Wamsutter area of Wyoming, which we expect to be in service at the end of 2010.
- We expect to begin construction in 2010 on a 12-inch pipeline in Canada, which will transport recovered natural gas liquids and olefins from our extraction plant in Ft. McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional recovered liquids in excess of those from our current agreements. We anticipate an in-service date in 2012.
- In conjunction with a long-term agreement with a major producer, we will construct and operate a 28-mile natural gas gathering pipeline in the Marcellus Shale region that will deliver to the Transco pipeline. Construction is expected to begin on the 20-inch pipeline in the latter part of 2010, and it is expected to be placed into service during 2011.
- In addition to our initial investment, we intend to invest additional capital within our Laurel Mountain joint venture to grow the existing gathering infrastructure in 2010 and beyond.

Year-Over-Year Operating Results

	Years Ended December 31, 2009	2008	2007
		(Millions)	
Segment revenues	$3,588	$5,180	$4,933
Segment profit (loss):			
Domestic gathering & processing	$ 637	$ 841	$ 897
NGL marketing, olefins and other	162	113	174
Venezuela	(68)	12	11
Indirect general and administrative expense	(91)	(95)	(88)
Total	$ 640	$ 871	$ 994

In order to provide additional clarity, our management's discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

2009 vs. 2008

The decrease in *segment revenues* is largely due to:

- A $716 million decrease in revenues associated with the production of NGLs primarily due to lower average NGL prices.
- A $457 million decrease in revenues in our olefins production business primarily due to lower average product prices, partially offset by higher volumes.
- A $438 million decrease in marketing revenues primarily due to lower average NGL and crude prices, partially offset by higher NGL volumes.

These decreases are partially offset by a $52 million increase in fee revenues primarily due to higher volumes resulting from connecting new supplies in the deepwater Gulf of Mexico in the latter part of 2008 and new fees for processing Exploration & Production's natural gas production at Willow Creek.

Segment costs and expenses decreased $1,443 million, or 33 percent, primarily as a result of:

- A $586 million decrease in marketing purchases primarily due to lower average NGL and crude prices, including the absence of a $19 million charge in 2008 to write-down the value of NGL and olefin inventories, partially offset by higher NGL volumes.
- A $445 million decrease in costs in our olefins production business primarily due to lower per-unit feedstock costs, including the absence of an $11 million charge in 2008 to write-down the value of olefin inventories, partially offset by higher volumes.
- A $435 million decrease in costs associated with the production of NGLs primarily due to lower average natural gas prices.
- A $40 million gain on the 2009 sale of our Cameron Meadows processing plant.
- The absence of $17 million of charges in 2008 related to an impairment, asset abandonments, and asset retirement obligations.

These decreases are partially offset by:

- A $39 million unfavorable change due primarily to foreign currency exchange gains in 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

- The absence of $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation (see Note 16 of Notes to Consolidated Financial Statements).

The decrease in Midstream's *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses* and a $75 million loss from investment related to the impairment of our investment in Accroven.

A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The decrease in *domestic gathering & processing segment profit* includes a $193 million decrease in the West region and an $11 million decrease in the Gulf Coast region.

The decrease in our West region's *segment profit* includes:

- A $213 million decrease in NGL margins due to a significant decrease in average NGL prices, partially offset by a significant decrease in production costs reflecting lower natural gas prices. NGL equity volumes were slightly higher as both periods were impacted by significant volume changes. Current year volumes include the unfavorable impact of certain producers electing to convert, in accordance with those gas processing agreements, from keep-whole to fee-based processing at the beginning of 2009. Prior year NGL equity volumes sold were unusually low primarily due to an increase in inventory as we transitioned from product sales at the plant to shipping volumes through a pipeline for sale downstream, lower ethane recoveries to accommodate restrictions on the volume of NGLs we could deliver into the pipelines, and hurricane-related disruptions at a third-party fractionation facility at Mont Belvieu, Texas, which resulted in an NGL inventory build-up. Lower NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline also favorably impacted NGL margins in 2009.

- An $8 million decrease in involuntary conversion gains related to our Ignacio plant. These insurance recoveries in both years were used to rebuild the plant.

- A $39 million increase in fee revenues primarily due to new fees for processing Exploration & Production's natural gas production at Willow Creek, unusually low gathering and processing volumes in the first quarter of 2008 related to severe winter weather conditions, and producers converting from keep-whole to fee-based processing in the first quarter of 2009.

The decrease in the Gulf Coast region's *segment profit* includes:

- A $68 million decrease in NGL margins reflecting lower average NGL prices and lower volumes. Lower production costs reflecting lower natural gas prices partially offset these decreases. Both periods were impacted by unfavorable volume changes. Current year volumes include the unfavorable impact of periods of reduced NGL recoveries during the first quarter due to unfavorable NGL economics and natural declines in production sources. Prior year volumes were unusually low primarily due to periods of reduced NGL recoveries during the fourth quarter and as a result of hurricanes in the third quarter.

- A $40 million gain in 2009 on the sale of our Cameron Meadows processing plant, partially offset by the absence of a $5 million involuntary conversion gain in 2008 related to our Cameron Meadows plant.

- $26 million higher fee revenues primarily due to higher volumes resulting from connecting new supplies in the Blind Faith prospect in the deepwater in the latter part of 2008.

- The absence of $16 million of charges in 2008 related to an impairment, asset abandonments, and asset retirement obligations.

- An $11 million increase in depreciation primarily due to our Blind Faith pipeline extensions that came into service during the latter part of 2008.

NGL marketing, olefins and other

The significant components of the increase in *segment profit* of our other operations include:

- $138 million in higher margins related to the marketing of NGLs and olefins primarily due to favorable changes in pricing while product was in transit during 2009 as compared to significant unfavorable changes in pricing while product was in transit in 2008 and the absence of a $19 million charge in 2008 to write-down the value of NGL and olefin inventories.
- A $41 million unfavorable change primarily due to foreign currency exchange gains in 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations.
- The absence of $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation.
- $12 million in lower margins in our olefins production business primarily due to lower average prices, partially offset by lower per-unit feedstock costs, including the absence of an $11 million charge in 2008 to write-down the value of olefin inventories, and higher volumes in 2009 related to the impact of third-party operational issues in 2008 that reduced off-gas supplies to our plant in Canada.
- The absence of an $8 million gain recognized in 2008 related to a final earn-out payment on a 2005 asset sale.

Venezuela

The decrease in *segment profit* for our Venezuela operations primarily reflects the previously discussed $75 million loss from investment related to Accroven.

2008 vs. 2007

The increase in *segment revenues* is largely due to:

- A $210 million increase in revenues in our olefins production business primarily due to higher average product prices and also to higher volumes sold associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.
- A $163 million increase in revenues associated with the production of NGLs primarily due to higher average NGL prices, partially offset by lower volumes. Lower volumes resulted from reduced ethane recoveries at the plants during the third and fourth quarters of 2008 compared to higher volumes during 2007 as we transitioned from shipping volumes through a pipeline for sale downstream to product sales at the plant.
- A $50 million increase in fee-based revenues primarily due to the West region, the deepwater Gulf Coast region and at our Conway fractionation and storage facilities.

These increases are partially offset by a $194 million decrease in marketing revenues primarily due to lower volumes, partially offset by higher prices.

Segment costs and expenses increased $368 million, or 9 percent, primarily as a result of:

- A $213 million increase in costs in our olefins production business due to higher feedstock prices and also to higher volumes produced associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007. The increase also includes a $10 million higher charge to write-down the value of olefin inventories.
- A $191 million increase in costs associated with the production of NGLs primarily due to higher average natural gas prices.
- A $100 million increase in operating costs including higher depreciation, repair costs and property insurance deductibles related to the hurricanes, gas transportation expenses in the eastern Gulf of Mexico,

employee costs, and higher costs associated with the increase of our ownership interest in the Geismar olefins facility.

These increases are partially offset by:

- A $68 million decrease in marketing purchases primarily due to lower volumes, partially offset by higher average NGL and crude prices and a $19 million charge in 2008 to write-down the value of NGL and olefin inventories.
- A $49 million favorable change related to foreign currency exchange gains primarily due to the revaluation of current assets held in U.S. dollars within our Canadian operations.
- $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation.
- A $16 million favorable change due to higher involuntary conversion gains in 2008 related to insurance recoveries in excess of the carrying value of our Ignacio and Cameron Meadows plants.

The decrease in Midstream's *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The decrease in *domestic gathering & processing segment profit* includes a $49 million decrease in the West region and a $7 million decrease in the Gulf Coast region.

The decrease in our West region's *segment profit* includes:

- A $45 million decrease in NGL margins due to a significant increase in costs associated with the production of NGLs reflecting higher natural gas prices and lower volumes sold. The decrease in volumes sold is primarily due to restricted transportation capacity, unfavorable ethane economics, an increase in inventory during 2008, hurricane-related disruptions at a third-party fractionation facility, and lower equity volumes as processing agreements change from keep-whole to fee-based. These decreases were partially offset by a full year of production from the fifth train at our Opal processing plant, which began production in the first quarter of 2007.
- A $35 million increase in operating costs driven by higher turbine and engine overhaul expenses, depreciation expense and employee costs.
- The absence of a $12 million favorable litigation outcome in 2007.
- A $24 million increase in fee revenues including new lease revenues from Gas Pipeline for the Parachute lateral transferred to Midstream in December 2007.
- A $12 million involuntary conversion gain in 2008 related to our Ignacio plant. These insurance recoveries were used to rebuild the plant.

The decrease in the Gulf Coast region's *segment profit* is primarily due to $39 million higher operating costs including higher depreciation, gas transportation expenses and hurricane repair and property insurance deductibles. These increased expenses are partially offset by $18 million higher NGL margins and $8 million higher fee revenues primarily due to connecting new supplies in the deepwater.

NGL marketing, olefins and other

The significant components of the decrease in *segment profit* of our other operations include:

- $123 million in lower margins related to the marketing of NGLs and olefins primarily due to the impact of a significant and rapid decline in NGL and olefin prices during the fourth quarter of 2008 on a higher volume of product inventory in transit. This also includes a $19 million charge in 2008 to write-down the value of NGL and olefin inventories.

- $33 million higher operating costs including higher costs associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007 and hurricane damage repair expense at the Geismar plant.

- A $56 million favorable change in foreign currency exchange gains related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

- $32 million of income in 2008 related to the partial settlement of our Gulf Liquids litigation.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring the majority of fuel and shrink gas and hedging natural gas liquids sales for Midstream. Gas Marketing also provides similar services to third parties, such as producers and natural gas processors. In addition, Gas Marketing manages various natural gas-related contracts such as transportation and storage along with the related hedges, including certain legacy natural gas contracts and positions. We do not expect our future segment profit will be significantly impacted by these legacy contracts and positions.

Overview of 2009

Gas Marketing's operating results for 2009 are unfavorable compared to 2008 primarily due to lower realized margins on our storage contracts. This decline was partially offset by reduced net losses on proprietary trading and legacy contracts and lower adjustments to the carrying value of our natural gas storage inventory.

Outlook for 2010

For 2010, Gas Marketing will focus on providing services that support our natural gas businesses. Gas Marketing's earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Realized revenues	$3,031	$6,385	$4,948
Net forward unrealized mark-to-market gains (losses)	21	27	(315)
Segment revenues	$3,052	$6,412	$4,633
Segment profit (loss)	$ (18)	$ 3	$ (337)

2009 vs. 2008

Realized revenues represent (1) revenue from the sale of natural gas and (2) gains and losses from the net financial settlement of derivative contracts. The decrease in *realized revenues* is primarily due to a decrease in physical natural gas revenue as a result of a 53 percent decrease in average prices on physical natural gas sales, slightly offset by a 3 percent increase in natural gas sales volumes. This decline in *realized revenues* is primarily related to both gas sales associated with our transportation and storage contracts and gas sales associated with marketing Exploration & Production's natural gas volumes. A corresponding decline in *segment costs and expenses* occurred in 2009.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The decrease in *net forward unrealized mark-to-market gains* *(losses)* is primarily related to the absence of a $10 million favorable impact in 2008 for the initial consideration of our own nonperformance risk in estimating the fair value of our derivative liabilities.

Total segment costs and expenses decreased $3,339 million, primarily due to a 54 percent decrease in average prices on physical natural gas purchases, slightly offset by a 3 percent increase in natural gas purchase volumes. This decrease is primarily related to the previously discussed gas purchases associated with both our transportation and storage contracts and gas purchases from Exploration and Production. This decline also includes a lower adjustment to the carrying value of natural gas inventory in storage. These adjustments totaled $7 million in 2009 compared to $35 million in 2008.

The unfavorable change in *segment profit (loss)* is primarily due to a decline in realized margins on our storage contracts partially offset by lower adjustments to the carrying value of our natural gas storage inventory and reduced net losses on proprietary trading and legacy contracts.

2008 vs. 2007

The increase in *realized revenues* is primarily due to an increase in physical natural gas revenue as a result of a 26 percent increase in average prices on physical natural gas sales. This is slightly offset by a decrease related to net financial settlements of derivative contracts.

The favorable change in *net forward unrealized mark-to-market gains (losses)* includes the effect of a $156 million loss realized in December 2007 related to a legacy derivative natural gas sales contract. We had previously accounted for this contract on an accrual basis under the normal purchases and normal sales exception. We discontinued normal purchase and normal sales treatment because it was no longer probable that the contract would not be net settled. In addition, 2008 reflects favorable price movements on our derivative positions executed to hedge the anticipated withdrawal of natural gas from storage.

Total segment costs and expenses increased $1,439 million, primarily due to a 33 percent increase in average prices on physical natural gas purchases. These increases were partially offset by the absence of a $20 million accrual for litigation contingencies in 2007.

The favorable change in *segment profit (loss)* is primarily due to the favorable change in *net forward unrealized mark-to-market gains (losses)*, which includes the absence of a 2007 loss recognized on a legacy derivative natural gas sales contract. The favorable change in *segment profit (loss)* also reflects the absence of a $20 million accrual for litigation contingencies in 2007, partially offset by a decline in accrual earnings.

Other

Year-Over-Year Operating Results

	Years Ended December 31,		
	2009	2008	2007
	(Millions)		
Segment revenues	$27	$24	$26
Segment loss	$(1)	$(3)	$(1)

The results of our Other segment are relatively comparable for all periods presented.

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2009, we continued to focus upon growth through disciplined investments in our natural gas businesses. Examples of this growth included:

- Continued investment in Exploration & Production's development drilling programs, as well as the acquisition of additional producing properties and our initial entry into the Marcellus Shale area.

- Expansion of Gas Pipeline's interstate natural gas pipeline system to meet the demand of growth markets.
- Continued investment in Midstream's Deepwater Gulf expansion projects and gas processing capacity in the western United States and our initial entry into the Marcellus Shale area.

These investments were primarily funded through our cash flow from operations, which totaled nearly $2.6 billion for 2009.

During 2009, global credit markets experienced significant instability, markets witnessed significant reductions in value, and energy commodity prices experienced significant and rapid declines. In consideration of our liquidity under these conditions, we note the following:

- We reduced our levels of capital expenditures.
- As of December 31, 2009, we have approximately $1.9 billion of cash and cash equivalents and approximately $2.1 billion of available credit capacity under our credit facilities. Our $1.5 billion credit facility does not expire until May 2012. Additionally, Exploration & Production has an unsecured credit agreement that serves to reduce our margin requirements related to our hedging activities. (See additional discussion in the following Available Liquidity section.)
- We have no significant debt maturities until 2011.
- Our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support. (See Note 15 of Notes to Consolidated Financial Statements.)

Strategic Restructuring

On February 17, 2010, we completed a strategic restructuring, which involved contributing a substantial majority of our domestic midstream and gas pipeline businesses, including our limited- and general-partner interests in Williams Pipeline Partners L.P. (WMZ), into Williams Partners L.P. (WPZ). We initially own approximately 84 percent of Williams Partners L.P., up from 24 percent of current partnership. Our total ownership percentage will decline to approximately 80 percent assuming the successful completion of the exchange offer for all of WMZ's publicly-held units. See "Strategic Restructuring" in Part I, Item 1 of this Form 10-K for further discussion of this potential exchange offer. We intend to hold our limited-partner and general-partner units for the long-term. As consideration for the asset contributions, we received proceeds from WPZ's debt issuance of approximately $3.5 billion, less WPZ's transaction fees and expenses, as well as 203 million WPZ Class C units, which are identical to common units, except for a prorated initial distribution. We also maintained our 2 percent general-partner interest. WPZ assumed approximately $2 billion of existing debt associated with the gas pipeline assets. In connection with the restructuring, we retired $3 billion of our debt and paid $574 million in related premiums. These amounts, as well as other transaction costs, were primarily funded with the cash consideration we received from WPZ. As a result of our restructuring, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions. (See Note 19 of Notes to Consolidated Financial Statements.)

Outlook

For 2010, we expect operating results and cash flows to improve from 2009 levels due to the impact of expected higher energy commodity prices. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from changes in commodity prices as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from Gas Pipeline;
- Hedged natural gas sales at Exploration & Production related to a significant portion of its production;
- Fee-based revenues from certain gathering and processing services at Midstream.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, and debt payments while maintaining a sufficient level of liquidity. In particular, we note the following assumptions for the coming year:

- We expect to maintain liquidity of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities.
- We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolving credit facilities, and proceeds from debt issuances and sales of equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $2.2 billion and $2.975 billion in 2010.

We expect capital and investment expenditures to total between $2.05 billion and $2.775 billion in 2010. Of this total, approximately 64 percent is considered nondiscretionary to meet legal, regulatory, and/or contractual requirements, to fund committed growth projects or to preserve the value of existing assets.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations;
- Sustained reductions in energy commodity prices from the range of current expectations.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2010. Our internal and external sources of liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and may be available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

	Credit Facilities Expiration	Year Ended December 31,2009
		(Millions)
Cash and cash equivalents(1)		$1,867
Available capacity under our unsecured revolving and letter of credit facilities:		
$700 million facilities(2)	October 2010	480
$1.5 billion facility(3)	May 2012	1,430
Available capacity under Williams Partners L.P.'s $200 million senior unsecured credit facility(3)	December 2012	188
		$3,965

(1) *Cash and cash equivalents* includes $31 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $648 million of *cash and cash equivalents* that is being utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) These facilities were originated primarily in support of our former power business.

(3) At December 31, 2009, we are in compliance with the financial covenants associated with these credit agreements. These credit facilities were impacted by our previously discussed restructuring transactions. Williams Partners L.P. established a new $1.75 billion, three-year, senior unsecured revolving credit facility, which replaces its previous $450 million credit facility (which was comprised of a $250 million term loan and a $200 million revolving credit facility). The full amount of the new credit facility is available to Williams Partners L.P. to the extent not otherwise utilized by Transco and Northwest Pipeline, and may be increased by up to an additional $250 million. Transco and Northwest Pipeline are co-borrowers and are each able to borrow up to $400 million under this new facility to the extent not otherwise utilized. Williams Partners L.P. utilized $250 million of the new facility to repay a term loan that was outstanding under its existing facility. As Williams Partners L.P. will be funding Midstream and Gas Pipeline projects, we reduced our approximately $1.5 billion unsecured credit facility that expires May 2012 to approximately $900 million and removed Transco and Northwest Pipeline as borrowers. See the financial covenants of the new facility in Note 19 of Notes to Consolidated Financial Statements.

Williams Pipeline Partners L.P. filed a shelf registration statement for the issuance of up to $1.5 billion aggregate principal amount of debt and limited partnership unit securities. The registration statement was declared effective on August 3, 2009.

Williams Partners L.P. filed a shelf registration statement as a well-known, seasoned issuer in October 2009 that allows it to issue an unlimited amount of registered debt and limited partnership unit securities.

At the parent-company level, we filed a shelf registration statement as a well-known, seasoned issuer in May 2009 that allows us to issue an unlimited amount of registered debt and equity securities.

Exploration & Production has an unsecured credit agreement with certain banks that, so long as certain conditions are met, serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. The agreement extends through December 2013. (See Note 11 of Notes to Consolidated Financial Statements.)

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. Following the closing of our 2010 restructuring, our investment-grade ratings were affirmed and the ratings for WPZ were upgraded to investment grade. The current ratings are as follows:

	WMB	WPZ
Standard and Poor's(1)		
Corporate Credit Rating	BBB−	BBB−
Senior Unsecured Debt Rating	BB+	BBB−
Outlook	Positive(4)	Positive(4)
Moody's Investors Service(2)		
Senior Unsecured Debt Rating	Baa3	Baa3(5)
Outlook	Stable	Stable(6)
Fitch Ratings(3)		
Senior Unsecured Debt Rating	BBB−	BBB−(7)
Outlook	Stable	Stable

(1) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

(2) A rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. The "1," "2," and "3" modifiers show the relative standing within a major category. A "1"

indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" indicates the lower end of the category.

(3) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" is considered speculative grade. Fitch may add a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

(4) On January 12, 2010, Standard & Poor's revised to positive from stable.

(5) On February 17, 2010, Moody's Investor Service revised to Baa3 from Ba2.

(6) On February 17, 2010, Moody's Investor Service revised to stable from negative.

(7) On February 2, 2010, Fitch Ratings revised to BBB- from BB.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of December 31, 2009, we estimate that a downgrade to a rating below investment grade would require us to post up to $585 million in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 2,572	$ 3,355	$ 2,237
Financing activities	166	(432)	(511)
Investing activities	(2,310)	(3,183)	(2,296)
Increase (decrease) in cash and cash equivalents	$ 428	$ (260)	$ (570)

Operating activities

Our *net cash provided by operating activities* in 2009 decreased from 2008 primarily due to the decrease in our operating results.

Significant transactions in 2008 include:

- We received $140 million of cash related to a favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations. (See Note 2 of Notes to Consolidated Financial Statements.)
- Transco paid $144 million of required refunds related to a general rate case with the FERC. (See Results of Operations — Segments, Gas Pipeline.)

Our *net cash provided by operating activities* in 2008 increased from 2007 primarily due to the increase in our earnings.

Financing activities

Significant transactions include:

2009

- We received $595 million net cash from the issuance of $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to fund general corporate expenses and capital expenditures. (See Note 11 of Notes to Consolidated Financial Statements.)
- We paid $256 million of quarterly dividends on common stock for the year ended December 31, 2009.

2008

- We received $362 million from the completion of the Williams Pipeline Partners L.P. initial public offering.
- We paid $474 million for the repurchase of our common stock. (See Note 12 of Notes to Consolidated Financial Statements.)
- Gas Pipeline received $75 million net proceeds from debt transactions.
- We paid $250 million of quarterly dividends on common stock for the year ended December 31, 2008.

2007

- We paid $526 million for the repurchase of our common stock. (See Note 12 of Notes to Consolidated Financial Statements.)
- We repurchased $22 million of our 8.125 percent senior unsecured notes due March 2012 and $213 million of our 7.125 percent senior unsecured notes due September 2011. Early retirement premiums paid were approximately $19 million.
- Northwest Pipeline issued $185 million of 5.95 percent senior unsecured notes due 2017 and retired $175 million of 8.125 percent senior unsecured notes due 2010. Early retirement premiums paid were approximately $7 million.
- Williams Partners L.P. acquired certain of our membership interests in Wamsutter LLC, the limited liability company that owns the Wamsutter system, from us for $750 million. Williams Partners L.P. completed the transaction after successfully closing a public equity offering of 9.25 million common units that yielded net proceeds of approximately $335 million. The partnership financed the remainder of the purchase price primarily through utilizing $250 million term loan borrowings under their $450 million five-year senior unsecured credit facility and issuing approximately $157 million of common units to us.
- We paid $233 million of quarterly dividends on common stock for the year ended December 31, 2007.

Investing activities

2009

- Capital expenditures totaled $2.4 billion, more than half of which related to Exploration & Production. Included was a $253 million payment by Exploration & Production for the purchase of additional properties in the Piceance basin. (See Results of Operations — Segments, Exploration & Production.)
- We received $148 million as a distribution from Gulfstream following its debt offering.
- We contributed $142 million to our investments, including $106 million related to our Laurel Mountain equity investment and $20 million related to our Gulfstream equity investment.

2008

- Capital expenditures totaled $3.4 billion and was primarily related to Exploration & Production's drilling activity. This total includes Exploration & Production's acquisitions of certain interests in the Piceance and Fort Worth basins.
- We received $148 million of cash from Exploration & Production's sale of a contractual right to a production payment.
- We contributed $111 million to our investments, including $90 million related to our Gulfstream equity investment.

2007

- Capital expenditures totaled $2.9 billion and was primarily related to Exploration & Production's drilling activity, mostly in the Piceance basin.
- We received $496 million of gross proceeds from the sale of substantially all of our power business.
- We purchased $304 million and received $353 million from the sale of auction rate securities. These were utilized as a component of our overall cash management program.

Off-Balance Sheet Financing Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Notes 9, 10, 11, 15, and 16 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations, including obligations related to discontinued operations.

	2010	2011-2012	2013-2014	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal(1)	$ 15	$2,139	$ —	$ 6,155	$ 8,309
Interest	619	1,113	938	4,273	6,943
Capital leases	2	—	1	—	3
Operating leases	70	64	45	138	317
Purchase obligations(2)	1,147	1,728	1,474	3,621	7,970
Other long-term liabilities, including current portion:					
Physical and financial derivatives(3)(4)	418	287	125	62	892
Other(5)(6)	—	—	—	—	—
Total	$2,271	$5,331	$2,583	$14,249	$24,434

(1) In February 2010, we completed our strategic restructuring and retired $3 billion of aggregate principal corporate debt and issued $3.5 billion aggregate principal amount of senior unsecured notes of WPZ. Additionally, WPZ established a new $1.75 billion three-year unsecured revolving credit facility which replaces its previous $450 million credit facility. WPZ utilized $250 million of the new facility to repay a term loan that was outstanding under the previous facility. Williams has reduced its existing $1.5 billion unsecured

revolving credit facility, which matures in May 2012, to $900 million. The below table shows the impact by period of this transaction:

	2010	2011-2012	2013-2014	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Retirement of $3 billion of aggregate principle corporate debt	$—	$(1,030)	$ —	$(1,970)	$(3,000)
Issuance of the $3.5 billion WPZ senior notes	—	—	—	3,500	3,500
Retirement of the $250 million term loan under WPZ's $450 million credit facility	—	(250)	—	—	(250)
Issuance of $250 million term loan under WPZ's new $1.75 billion credit facility	—	—	250	—	250
Total	$—	$(1,280)	$250	$ 1,530	$ 500

(2) Includes $3.2 billion of natural gas purchase obligations at market prices at our Exploration & Production segment. The purchased natural gas can be sold at market prices.

(3) The obligations for physical and financial derivatives are based on market information as of December 31, 2009, and assumes contracts remain outstanding for their full contractual duration. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(4) Expected offsetting cash inflows of $3.9 billion at December 31, 2009, resulting from product sales or net positive settlements, are not reflected in these amounts. In addition, product sales may require additional purchase obligations to fulfill sales obligations that are not reflected in these amounts.

(5) Does not include estimated contributions to our pension and other postretirement benefit plans. We made contributions to our pension and other postretirement benefit plans of $77 million in 2009 and $75 million in 2008. In 2010, we expect to contribute approximately $77 million to these plans (see Note 7 of Notes to Consolidated Financial Statements). During 2009, we contributed $60 million to our tax-qualified pension plans which was greater than the minimum funding requirements. We expect to contribute approximately $60 million to these pension plans again in 2010, which is expected to be greater than the minimum funding requirements. Estimated future minimum funding requirements may vary significantly from historical requirements if actual results differ significantly from estimated results for assumptions such as returns on plan assets, interest rates, retirement rates, mortality, and other significant assumptions or by changes to current legislation and regulations.

(6) As of December 31, 2009, we have accrued approximately $72 million for unrecognized tax benefits. We cannot make reasonably reliable estimates of the timing of the future payments of these liabilities. Therefore, these liabilities have been excluded from the table above. See Note 5 of Notes to Consolidated Financial Statements for information regarding our contingent tax liability reserves.

Effects of Inflation

Our operations have benefited from relatively low inflation rates. Approximately 37 percent of our gross property, plant and equipment is at Gas Pipeline. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulation, along with competition and other market factors, may limit our ability to recover such increased costs. For the other operating units, operating costs are influenced to a greater extent by both competition for specialized services and specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, natural gas, and natural gas liquids prices are particularly sensitive to the Organization of the Petroleum Exporting Countries (OPEC) production levels and/or the market perceptions concerning the supply and demand balance in the near future, as well as general economic conditions. However, our exposure to these price changes is reduced through the use of hedging instruments and the fee-based nature of certain of our services.

Environmental

We are a participant in certain environmental activities in various stages including assessment studies, cleanup operations and/or remedial processes at certain sites, some of which we currently do not own (see Note 16 of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such activities are approximately $42 million, all of which are recorded as liabilities on our balance sheet at December 31, 2009. We will seek recovery of approximately $12 million of these accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2009, we paid approximately $8 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $10 million in 2010 for these activities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. At December 31, 2009, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type, and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990, which require the EPA to issue new regulations. We are also subject to regulation at the state and local level. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. Revisions to those rules were proposed in January 2010 and may result in additional controls. In March 2004 and June 2004, the EPA promulgated additional regulation regarding hazardous air pollutants, which may result in additional controls. Capital expenditures necessary to install emission control devices on our Transco gas pipeline system to comply with rules were approximately $400 thousand in 2009 and are estimated to be between $5 million and $10 million through 2013. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. We consider these costs on our Transco system associated with compliance with these environmental laws and regulations to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through its rates.

We have established systems and procedures to meet our reporting obligations under the Mandatory Reporting Rule related to greenhouse gas emissions issued by the EPA in late 2009. Also, certain states in which we have operations have established reporting obligations. We have not incurred significant capital investment to meet the obligations imposed by these new rules. The EPA is developing additional regulations that will expand the scope of the Mandatory Reporting Rule, with particular emphasis on natural gas operations. We are participating directly and through trade associations in developmental aspects of that prospective rulemaking. It is likely that additional rules will be issued in 2010 which may expand our reporting obligations as early as 2011. As those rules are still being developed, at this time we are unable to estimate any capital investment that may be required to comply.

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

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio. The majority of our debt portfolio is comprised of fixed rate debt in order to mitigate the impact of fluctuations in interest rates. The maturity of our long-term debt portfolio is partially influenced by the expected lives of our operating assets. In February 2010, we completed a strategic restructuring that involved retiring $3 billion of our debt and issuing $3.5 billion aggregate principal amount of senior unsecured notes of WPZ. (See Note 19 of Notes to Consolidated Financial Statements.)

The tables below provide information by maturity date about our interest rate risk-sensitive instruments included in continuing operations as of December 31, 2009 and 2008. Long-term debt in the tables represents principal cash flows, net of (discount) premium, and weighted-average interest rates by expected maturity dates. The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings.

	2010	2011	2012	2013	2014	Thereafter(1)	Total	Fair Value December 31, 2009
					(Millions)			
Long-term debt, including current portion(2):								
Fixed rate	$ 15	$936	$953	$—	$—	$6,119	$8,023	$8,905
Interest rate	7.7%	7.7%	7.7%	7.7%	7.7%	8.0%		
Variable rate	$—	$ —	$250	$—	$—	$ —	$ 250	$ 237
Interest rate(3)								

	2009	2010	2011	2012	2013	Thereafter(1)	Total	Fair Value December 31, 2008
					(Millions)			
Long-term debt, including current portion(2):								
Fixed rate	$ 15	$—	$927	$953	$—	$5,551	$7,446	$5,907
Interest rate	7.6%	7.6%	7.6%	7.6%	7.5%	7.9%		
Variable rate	$—	$—	$ —	$250	$—	$ —	$ 250	$ 233
Interest rate(3)								

(1) Includes unamortized discount and premium.

(2) Excludes capital leases.

(3) The interest rate at December 31, 2009 and 2008 is LIBOR plus 1 percent and 0.75 percent, respectively.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and NGLs, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives is a net liability of $11 million at December 31, 2009. Our value at risk for contracts held for trading purposes was less than $1 million at December 31, 2009 and 2008.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	• Natural gas sales
Midstream	• Natural gas purchases • NGL purchases and sales
Gas Marketing Services	• Natural gas purchases and sales

The fair value of our nontrading derivatives is a net asset of $99 million at December 31, 2009.

The value at risk for derivative contracts held for nontrading purposes was $34 million at December 31, 2009, and $33 million at December 31, 2008. During the year ended December 31, 2009, our value at risk for these contracts ranged from a high of $37 million to a low of $27 million.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges have a net asset value of $178 million as of December 31, 2009. Though these contracts are included in our value-at-risk calculation, any change in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Trading Policy

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Foreign Currency Risk

We have international investments that could affect our financial results if the investments incur a permanent decline in value as a result of changes in foreign currency exchange rates and/or the economic conditions in foreign countries.

International investments accounted for under the cost method totaled $2 million at December 31, 2009, and $17 million at December 31, 2008. These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value. We believe that we can realize the carrying value of these investments considering the status of the operations of the companies underlying these investments.

Net assets of consolidated foreign operations, whose functional currency is the local currency, are located primarily in Canada and approximate 6 percent and 5 percent of our net assets at December 31, 2009 and 2008, respectively. These foreign operations do not have significant transactions or financial instruments denominated in currencies other than their functional currency. However, these investments do have the potential to impact our financial position, due to fluctuations in these local currencies arising from the process of translating the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar would have changed *stockholders' equity* by approximately $98 million at December 31, 2009.

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

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934). Our internal controls over financial reporting are designed to provide reasonable assurance to our management and board of directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and board of directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2009, based on the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework.* Based on our assessment, we concluded that, as of December 31, 2009, our internal control over financial reporting was effective.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Annual Report on Form 10-K.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited The Williams Companies, Inc.'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 (the COSO criteria). The Williams Companies, Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2009 of The Williams Companies, Inc. and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
The Williams Companies, Inc.

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2009. Our audits also included the financial statement schedule listed in the index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 9 to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), The Williams Companies, Inc.'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 and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2010

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF INCOME

	Years Ended December 31,		
	2009	2008	2007
	(Millions, except per-share amounts)		
Revenues:			
Exploration & Production	$ 2,219	$ 3,121	$ 2,021
Gas Pipeline	1,591	1,634	1,610
Midstream Gas & Liquids	3,588	5,180	4,933
Gas Marketing Services	3,052	6,412	4,633
Other	27	24	26
Intercompany eliminations	(2,222)	(4,481)	(2,984)
Total revenues	8,255	11,890	10,239
Segment costs and expenses:			
Costs and operating expenses	6,081	8,776	7,832
Selling, general and administrative expenses	512	504	461
Other (income) expense — net	17	(72)	(2)
Total segment costs and expenses	6,610	9,208	8,291
General corporate expenses	164	149	161
Operating income (loss):			
Exploration & Production	400	1,240	731
Gas Pipeline	601	630	622
Midstream Gas & Liquids	663	812	933
Gas Marketing Services	(18)	3	(337)
Other	(1)	(3)	(1)
General corporate expenses	(164)	(149)	(161)
Total operating income	1,481	2,533	1,787
Interest accrued	(661)	(636)	(664)
Interest capitalized	76	59	32
Investing income	46	189	252
Early debt retirement costs	(1)	(1)	(19)
Other income — net	2	—	12
Income from continuing operations before income taxes	943	2,144	1,400
Provision for income taxes	359	677	490
Income from continuing operations	584	1,467	910
Income (loss) from discontinued operations	(223)	125	170
Net income	361	1,592	1,080
Less: Net income attributable to noncontrolling interests	76	174	90
Net income attributable to The Williams Companies, Inc.	$ 285	$ 1,418	$ 990
Amounts attributable to The Williams Companies, Inc.:			
Income from continuing operations	$ 438	$ 1,306	$ 829
Income (loss) from discontinued operations	(153)	112	161
Net income	$ 285	$ 1,418	$ 990
Basic earnings (loss) per common share:			
Income from continuing operations	$ .75	$ 2.25	$ 1.39
Income (loss) from discontinued operations	(.26)	.19	.27
Net income	$ .49	$ 2.44	$ 1.66
Weighted-average shares (thousands)	581,674	581,342	596,174
Diluted earnings (loss) per common share:			
Income from continuing operations	$ .75	$ 2.21	$ 1.37
Income (loss) from discontinued operations	(.26)	.19	.26
Net income	$ .49	$ 2.40	$ 1.63
Weighted-average shares (thousands)	589,385	592,719	609,866

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2009	December 31, 2008
	(Millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,867	$ 1,438
Accounts and notes receivable (net of allowance of $22 at December 31, 2009 and $29 at December 31, 2008)	829	884
Inventories	222	260
Derivative assets	650	1,464
Assets of discontinued operations	1	142
Other current assets and deferred charges	224	223
Total current assets	3,793	4,411
Investments	886	971
Property, plant and equipment — net	18,644	17,741
Derivative assets	444	986
Goodwill	1,011	1,011
Assets of discontinued operations	—	387
Other assets and deferred charges	502	499
Total assets	$25,280	$26,006
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 934	$ 1,052
Accrued liabilities	948	1,139
Derivative liabilities	578	1,093
Liabilities of discontinued operations	—	217
Long-term debt due within one year	17	18
Total current liabilities	2,477	3,519
Long-term debt	8,259	7,683
Deferred income taxes	3,656	3,315
Derivative liabilities	428	875
Liabilities of discontinued operations	—	82
Other liabilities and deferred income	1,441	1,478
Contingent liabilities and commitments (Note 16)		
Equity:		
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 618 million shares issued at December 31, 2009, and 613 million shares issued at December 31, 2008)	618	613
Capital in excess of par value	8,135	8,074
Retained earnings	903	874
Accumulated other comprehensive loss	(168)	(80)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders' equity	8,447	8,440
Noncontrolling interests in consolidated subsidiaries	572	614
Total equity	9,019	9,054
Total liabilities and equity	$25,280	$26,006

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	The Williams Companies, Inc., Stockholders							
	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Treasury Stock	Total Stockholders' Equity	Noncontrolling Interests	Total
	(Millions, except per-share amounts)							
Balance, December 31, 2006	$603	$6,605	$(1,034)	$ (60)	$ (41)	$6,073	$ 1,081	$7,154
Comprehensive income:								
Net income	—	—	990	—	—	990	90	1,080
Other comprehensive loss:								
Net change in cash flow hedges (Note 17)	—	—	—	(177)	—	(177)	(2)	(179)
Foreign currency translation adjustments	—	—	—	53	—	53	—	53
Pension benefits:								
Net actuarial gain	—	—	—	53	—	53	—	53
Other postretirement benefits:								
Prior service cost	—	—	—	1	—	1	—	1
Net actuarial gain	—	—	—	9	—	9	—	9
Total other comprehensive loss						(61)	(2)	(63)
Total comprehensive income						929	88	1,017
Cash dividends — Common stock ($.39 per share)	—	—	(233)	—	—	(233)	—	(233)
Sale of limited partner units of consolidated partnership	—	—	—	—	—	—	333	333
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(75)	(75)
Initial adjustment for uncertain tax positions	—	—	(17)	—	—	(17)	—	(17)
Purchase of treasury stock (Note 12)	—	—	—	—	(526)	(526)	—	(526)
Stock-based compensation, including tax benefit	5	143	—	—	—	148	—	148
Other	—	—	1	—	—	1	3	4
Balance, December 31, 2007	608	6,748	(293)	(121)	(567)	6,375	1,430	7,805
Comprehensive income:								
Net income	—	—	1,418	—	—	1,418	174	1,592
Other comprehensive income:								
Net change in cash flow hedges (Note 17)	—	—	—	453	—	453	2	455
Foreign currency translation adjustments	—	—	—	(76)	—	(76)	—	(76)
Pension benefits:								
Prior service cost	—	—	—	1	—	1	—	1
Net actuarial loss	—	—	—	(337)	—	(337)	(7)	(344)
Other postretirement benefits:								
Prior service cost	—	—	—	9	—	9	—	9
Net actuarial loss	—	—	—	(9)	—	(9)	—	(9)
Total other comprehensive income						41	(5)	36
Total comprehensive income						1,459	169	1,628
Cash dividends — Common stock ($.43 per share)	—	—	(250)	—	—	(250)	—	(250)
Sale of limited partner units of consolidated partnership	—	—	—	—	—	—	362	362
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(122)	(122)
Issuance of common stock from 5.5% debentures conversion (Note 12)	2	25	—	—	—	27	—	27
Conversion of Williams Partners L.P. subordinated units to common units (Note 12)	—	1,225	—	—	—	1,225	(1,225)	—
Purchase of treasury stock (Note 12)	—	—	—	—	(474)	(474)	—	(474)
Stock-based compensation, including tax benefit	3	67	—	—	—	70	—	70
Other	—	9	(1)	—	—	8	—	8
Balance, December 31, 2008	613	8,074	874	(80)	(1,041)	8,440	614	9,054
Comprehensive income:								
Net income	—	—	285	—	—	285	76	361
Other comprehensive loss:								
Net change in cash flow hedges (Note 17)	—	—	—	(221)	—	(221)	—	(221)
Foreign currency translation adjustments	—	—	—	83	—	83	—	83
Pension benefits:								
Net actuarial gain	—	—	—	46	—	46	7	53
Other postretirement benefits:								
Prior service cost	—	—	—	4	—	4	—	4
Total other comprehensive loss						(88)	7	(81)
Total comprehensive income						197	83	280
Cash dividends — Common stock ($.44 per share)	—	—	(256)	—	—	(256)	—	(256)
Dividends and distributions to noncontrolling interests	—	—	—	—	—	—	(129)	(129)
Issuance of common stock from 5.5% debentures conversion (Note 12)	3	25	—	—	—	28	—	28
Stock-based compensation, including tax benefit	2	36	—	—	—	38	—	38
Other	—	—	—	—	—	—	4	4
Balance, December 31, 2009	$618	$8,135	$ 903	$(168)	$(1,041)	$8,447	$ 572	$9,019

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 361	$ 1,592	$ 1,080
Adjustments to reconcile to net cash provided by operating activities:			
Reclassification of deferred net hedge gains related to sale of power business	—	—	(429)
Depreciation, depletion and amortization	1,469	1,310	1,082
Provision for deferred income taxes	249	611	370
Provision for loss on investments, property and other assets	386	166	162
Net (gain) loss on dispositions of assets and business	(44)	(36)	16
Gain on sale of contractual production rights	—	(148)	—
Early debt retirement costs	1	1	19
Provision for doubtful accounts and notes	48	15	12
Amortization of stock-based awards	43	31	70
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	67	329	(122)
Inventories	33	(48)	29
Margin deposits and customer margin deposits payable	4	88	(135)
Other current assets and deferred charges	(8)	(76)	(10)
Accounts payable	5	(343)	26
Accrued liabilities	(170)	7	(200)
Changes in current and noncurrent derivative assets and liabilities	36	(121)	370
Other, including changes in noncurrent assets and liabilities	92	(23)	(103)
Net cash provided by operating activities	2,572	3,355	2,237
FINANCING ACTIVITIES:			
Proceeds from long-term debt	595	674	684
Payments of long-term debt	(33)	(665)	(806)
Proceeds from issuance of common stock	6	32	56
Proceeds from sale of limited partner units of consolidated partnerships	—	362	333
Tax benefit of stock-based awards	1	21	32
Dividends paid	(256)	(250)	(233)
Purchase of treasury stock	—	(474)	(526)
Premiums paid on early debt retirements and tender offer	—	—	(27)
Dividends and distributions paid to noncontrolling interests	(129)	(122)	(75)
Changes in cash overdrafts	(51)	—	52
Other — net	33	(10)	(1)
Net cash provided (used) by financing activities	166	(432)	(511)
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures*	(2,387)	(3,394)	(2,868)
Net proceeds from dispositions	72	119	12
Purchases of investments/advances to affiliates	(142)	(111)	(60)
Purchases of auction rate securities	—	—	(304)
Purchases of ARO trust investments	(46)	(31)	—
Proceeds from sales of ARO trust investments	41	14	—
Proceeds from sale of business	—	22	471
Proceeds from dispositions of investments and other assets	3	41	92
Proceeds from sales of auction rate securities	—	—	353
Proceeds from sale of contractual production rights	—	148	—
Distribution from Gulfstream Natural Gas System, L.L.C.	148	—	—
Other — net	1	9	8
Net cash used by investing activities	(2,310)	(3,183)	(2,296)
Increase (decrease) in cash and cash equivalents	428	(260)	(570)
Cash and cash equivalents at beginning of year	1,439	1,699	2,269
Cash and cash equivalents at end of year	1,867	1,439	1,699

* Increases to property, plant and equipment	(2,314)	(3,475)	(2,816)
Changes in related accounts payable and accrued liabilities	(73)	81	(52)
Capital expenditures	$(2,387)	$(3,394)	$(2,868)

See accompanying notes.

Note 1. Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services (Gas Marketing).

Exploration & Production includes natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States and oil and natural gas interests in South America.

Gas Pipeline is comprised primarily of two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies. Gas Pipeline includes Northwest Pipeline GP (Northwest Pipeline), which extends from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington, and Transcontinental Gas Pipe Line Company, LLC (Transco), which extends from the Gulf of Mexico region to the northeastern United States. In addition, we own a 50 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream). Gulfstream is a natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida.

Midstream is comprised of natural gas gathering and processing and treating facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States, oil gathering and transportation facilities in the Gulf Coast region of the United States, and assets in Canada, consisting primarily of a natural gas liquids extraction facility and a fractionation plant.

Gas Marketing primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids (NGLs) sales for Midstream. Gas Marketing also provides similar services to third parties, such as producers. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, related hedges and proprietary trading positions.

Basis of Presentation

Prior period amounts reported for Midstream have been adjusted for certain contracts involving the purchase and resale of NGLs and/or oil with the same counterparties that should have been reported on a net, rather than gross, basis. The error in presentation overstated both *revenues* and *costs and operating expenses* by equal amounts and had no impact on *segment profit, operating income, net income, net cash provided by operating activities* or any other key internal measures of operating performance. These adjustments reduced previously reported *revenues* and *costs and operating expenses* by $295 million in 2008 and $99 million in 2007.

Discontinued operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of certain of our Venezuela operations and our former power business as discontinued operations. (See Note 2). Our former power business included a 7,500-megawatt portfolio of power-related contracts that was sold in 2007 and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton) that was sold in March 2008, in addition to other power-related assets.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

Master limited partnerships

As of December 31, 2009, we own approximately 23.6 percent of Williams Partners L.P. (WPZ), including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner, we consolidate WPZ within our Midstream segment.

As of December 31, 2009, we own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P. (WMZ), including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. We consolidate WMZ within our Gas Pipeline segment due to our control through the general partner.

Our overall ownership in WPZ and WMZ has been impacted by our restructuring transactions in 2010. (See Note 19.)

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned or controlled subsidiaries and investments. We apply the equity method of accounting for investments in unconsolidated companies in which we and our subsidiaries own 20 to 50 percent of the voting interest, otherwise exercise significant influence over operating and financial policies of the company, or where majority ownership does not provide us with control due to significant participatory rights of other owners.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Significant estimates and assumptions include:

- Impairment assessments of investments, long-lived assets and goodwill;
- Litigation-related contingencies;
- Valuations of derivatives;
- Hedge accounting correlations and probability;
- Environmental remediation obligations;
- Realization of deferred income tax assets;
- Valuation of Exploration & Production's reserves;
- Asset retirement obligations;
- Pension and postretirement valuation variables.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Our *cash and cash equivalents* balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is generally recognized at the time full payment is received or collectability is assured. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.

Inventory valuation

All *inventories* are stated at the lower of cost or market. The cost of inventories is primarily determined using the average-cost method. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. LIFO inventory at December 31, 2009 and 2008, is $7 million and $11 million, respectively.

Property, plant and equipment

Property, plant and equipment is recorded at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values.

As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at Federal Energy Regulatory Commission (FERC)-prescribed rates. See Note 9 for depreciation rates used for major regulated gas plant facilities.

Depreciation for nonregulated entities is provided primarily on the straight-line method over estimated useful lives, except as noted below for oil and gas exploration and production activities. See Note 9 for the estimated useful lives associated with our nonregulated assets.

Gains or losses from the ordinary sale or retirement of property, plant and equipment for regulated pipelines are credited or charged to accumulated depreciation; other gains or losses are recorded in *other (income) expense — net* included in *operating income*.

Ordinary maintenance and repair costs are generally expensed as incurred. Costs of major renewals and replacements are capitalized as *property, plant, and equipment — net.*

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells, as applicable, are capitalized as incurred. If proved reserves are not found, such costs are charged to expense. Other exploration costs, including lease rentals, are expensed as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred. *Depreciation, depletion and amortization* is provided under the units-of-production method on a field basis.

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation (ARO). The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense included in *other (income) expense — net* included in *operating income*, except for regulated entities, for which the liability is offset by a regulatory asset.

Goodwill

Goodwill represents the excess of cost over fair value of the assets of businesses acquired. It is evaluated at least annually for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. We also consider our market capitalization to corroborate our estimate of the fair value of the reporting unit. We have *goodwill* of approximately $1 billion at December 31, 2009 and 2008, attributable to our Exploration & Production segment.

When a reporting unit is sold or classified as held for sale, any goodwill of that reporting unit is included in its carrying value for purposes of determining any impairment or gain/loss on sale. If a portion of a reporting unit with goodwill is sold or classified as held for sale and that asset group represents a business, a portion of the reporting unit's goodwill is allocated to and included in the carrying value of that asset group. None of the operations sold during the periods reported represented reporting units with goodwill or businesses within reporting units to which goodwill was required to be allocated.

Judgments and assumptions are inherent in our management's estimate of future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements. Given the challenges affecting our businesses and the energy industry in 2010, we may be required to perform interim assessments of goodwill for possible impairment during 2010, which could result in a material impairment of our goodwill.

Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to *capital in excess of par value* using the average-cost method.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except for those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheet in *derivative assets* and *derivative liabilities* as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

Derivative Treatment	Accounting Method
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

We have also designated a hedging relationship for certain commodity derivatives. For a derivative to qualify for designation in a hedging relationship, it must meet specific criteria and we must maintain appropriate documentation. We establish hedging relationships pursuant to our risk management policies. We evaluate the hedging relationships at the inception of the hedge and on an ongoing basis to determine whether the hedging relationship is, and is expected to remain, highly effective in achieving offsetting changes in fair value or cash flows attributable to the underlying risk being hedged. We also regularly assess whether the hedged forecasted transaction is probable of occurring. If a derivative ceases to be or is no longer expected to be highly effective, or if we believe the likelihood of occurrence of the hedged forecasted transaction is no longer probable, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized currently in *revenues* or *costs and operating expenses* dependent upon the underlying hedge transaction.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in *accumulated other comprehensive loss* and reclassified into earnings in the period in which the hedged item affects earnings. Any ineffective portion of the derivative's change in fair value is recognized currently in *revenues* or *costs and operating expenses*. Gains or losses deferred in *accumulated other comprehensive loss* associated with terminated derivatives, derivatives that cease to be highly effective hedges, derivatives for which the forecasted transaction is reasonably possible but no longer probable of occurring, and cash flow hedges that have been otherwise discontinued remain in *accumulated other comprehensive loss* until the hedged item affects earnings. If it becomes probable that the forecasted transaction designated as the hedged item in a cash flow hedge will not occur, any gain or loss deferred in *accumulated other comprehensive loss* is recognized in *revenues* or *costs and operating expenses* at that time. The change in likelihood is a judgmental decision that includes qualitative assessments made by management.

For commodity derivatives that are not designated in a hedging relationship, and for which we have not elected the normal purchases and normal sales exception, we report changes in fair value currently in *revenues*.

Certain gains and losses on derivative instruments included in the Consolidated Statement of Income are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;
- The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;
- Realized gains and losses on all derivatives that settle financially other than natural gas derivatives for NGL processing activities;
- Realized gains and losses on derivatives held for trading purposes;
- Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives for NGL processing activities and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Gas Pipeline revenues

Gas Pipeline revenues are primarily from services pursuant to long-term firm transportation and storage agreements. These agreements provide for a demand charge based on the volume of contracted capacity and a commodity charge based on the volume of gas delivered, both at rates specified in our FERC tariffs. We recognize revenues for demand charges ratably over the contract period regardless of the volume of natural gas that is transported or stored. Revenues for commodity charges, from both firm and interruptible transportation services, and storage injection and withdrawal services, are recognized when natural gas is delivered at the agreed upon delivery point or when natural gas is injected or withdrawn from the storage facility.

In the course of providing transportation services to customers, we may receive different quantities of gas from shippers than the quantities delivered on behalf of those shippers. The resulting imbalances are primarily settled through the purchase and sale of gas with our customers under terms provided for in our FERC tariffs. Revenue is recognized from the sale of gas upon settlement of the transportation and exchange imbalances.

As a result of the ratemaking process, certain revenues collected by us may be subject to refunds upon the issuance of final orders by the FERC in pending rate proceedings. We record estimates of rate refund liabilities considering our and other third-party regulatory proceedings, advice of counsel and other risks.

Exploration & Production revenues

Revenues from the domestic production of natural gas in properties for which Exploration & Production has an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on Exploration & Production's net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

Midstream revenues

Natural gas gathering and processing services are performed under volumetric-based fee contracts, keep-whole agreements and percent-of-liquids arrangements. Revenues under volumetric-based fee contracts are recorded when services have been performed. Under keep-whole and percent-of-liquids processing contracts, we retain the rights to all or a portion of the NGLs extracted from the producers' natural gas stream and recognize revenues when the extracted NGLs are sold and delivered.

We have olefins extraction operations where we retain certain products extracted from the producers' off-gas stream and we recognize revenues when the extracted products are sold and delivered to our purchasers. We also produce olefins from purchased feed-stock, and we recognize revenues when the olefins are sold and delivered.

We also market NGLs and olefins. Revenues from marketing NGLs and olefins are recognized when the products have been sold and delivered.

Gas Marketing revenues

Revenues for sales of natural gas are recognized when the product is sold and delivered.

All other revenues

Revenues generally are recorded when services are performed or products have been delivered.

Impairment of long-lived assets and investments

We evaluate the long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. Except for proved and unproved properties discussed below, when an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred and we apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

For assets identified to be disposed of in the future and considered held for sale, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is recalculated when related events or circumstances change.

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the book value of the assets, then a subsequent analysis is performed using discounted cash flows. Estimating future cash flows involves the use of complex judgments such as estimation of the oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production, expected future commodity prices, capital expenditures, and production costs.

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. A majority of the costs of acquired unproved reserves are associated with areas to which proved developed producing reserves are also attributed. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of potentially recoverable reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. Costs of acquired unproved reserves are assessed annually, or as conditions warrant, for impairment using estimated future discounted cash flows on a field basis and considering our future drilling plans. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other-than-temporary, the excess of the carrying value over the fair value is recognized in the consolidated financial statements as an impairment.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows and an asset's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements.

Capitalization of interest

We capitalize interest during construction on major projects with construction periods of at least three months and a total project cost in excess of $1 million. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds as a component of *other income — net*. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by nonregulated companies are based on the average interest rate on debt.

Employee stock-based awards

Total stock-based compensation expense for the years ending December 31, 2009, 2008, and 2007 was $43 million, $31 million, and $70 million, respectively, of which $1 million and $9 million in 2008 and 2007, respectively, is included in *income (loss) from discontinued operations*. Measured but unrecognized stock-based compensation expense at December 31, 2009, was approximately $44 million, which does not include the effect of estimated forfeitures of $2 million. This amount is comprised of approximately $7 million related to stock options and approximately $37 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.7 years.

Income taxes

We include the operations of our subsidiaries in our consolidated tax return. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. *Diluted earnings (loss) per common share* includes any dilutive effect of stock options, nonvested restricted stock units and, for applicable periods presented, convertible debt, unless otherwise noted.

Foreign currency translation

Certain of our foreign subsidiaries use their local currency as their functional currency. These foreign currencies include the Canadian dollar, British pound and Euro. Assets and liabilities of certain foreign subsidiaries are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of *accumulated other comprehensive loss.*

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transaction gains and losses which are reflected in the Consolidated Statement of Income.

Issuance of equity of consolidated subsidiary

Sales of residual equity interests in a consolidated subsidiary are accounted for as capital transactions. No adjustments to capital are made for sales of preferential interests in a subsidiary. No gain or loss is recognized on these transactions.

Accounting Standards Issued But Not Yet Adopted

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, "Fair Value Measurements and Disclosures (Topic 820) — Improving Disclosures about Fair Value Measurements." This Update requires new disclosures regarding the amount of transfers in or out of Levels 1 and 2 along with the reason for such transfers and also requires a greater level of disaggregation when disclosing valuation techniques and inputs used in estimating Level 2 and Level 3 fair value measurements. This Update also includes conforming amendments to the guidance on employers' disclosures about postretirement benefit plan assets. The disclosures will be required for reporting beginning in the first quarter 2010. Also, beginning with the first quarter 2011, the Standard requires additional categorization of items included in the rollforward of activity for Level 3 inputs on a gross basis. We are assessing the application of this Standard to disclosures in our Consolidated Financial Statements.

Subsequent Events

We have evaluated our disclosure of subsequent events through the time of filing this Form 10-K with the Securities and Exchange Commission on February 25, 2010.

Note 2. Discontinued Operations

Our Venezuela operations include majority ownership in entities that owned and operated the El Furrial and PIGAP II gas compression facilities prior to their expropriation by the Venezuelan government in May 2009. We previously operated these assets under long-term agreements for the exclusive benefit of the state-owned oil company, Petróleos de Venezuela S.A. (PDVSA). Construction of these assets was funded through project financing that is collateralized by the stock, assets, and contract rights of the entities that operated the Venezuela assets and is nonrecourse to us. We and the secured lenders are pursuing rights available to us under our agreements, including contractual and international arbitration. These operations met the accounting definition of a component of an entity. As a result of the expropriation of the assets and the termination of the associated contracts, we consider these assets to be disposed and thus qualified for reporting as discontinued operations.

Considering the expropriation of the assets and the significant controlling rights of the secured lenders, we no longer control these entities and no longer meet the criteria to consolidate them. In conjunction with the deconsolidation of these entities in the second quarter of 2009, we recorded our retained investment in these entities at zero and recognized a pre-tax gain of $9 million. This carrying value was based on our estimates of probability-weighted discounted cash flows that considered: (1) alternate arbitration venues, (2) estimated levels of arbitration awards, (3) the subsequent likelihood and timing of collection, (4) the duration of the arbitration process, (5) a discount rate of 20 percent, and (6) the allocation of arbitration proceeds between parties, including the secured lenders. The use of alternate judgments and/or assumptions would have resulted in a different gain on deconsolidation. The carrying value of our retained investment in these entities was significantly impacted by our assumptions and is not representative of our underlying claims against PDVSA or the country of Venezuela.

The expropriations in the second quarter of 2009 followed an extended period of nonpayment by PDVSA and default notices that we provided in accordance with our agreements. The collection of receivables from PDVSA was historically slower and required more effort than with other customers due to PDVSA's policies and the political environment in Venezuela. In our year-end 2008 analysis, we expected PDVSA to resume regular payments following a February 15, 2009, referendum vote in Venezuela; however, that did not happen. PDVSA's continued nonperformance across the industry, their financial distress, and lack of communications with us caused us to revise our assessment in the first quarter of 2009.

As a result of this and our first-quarter assessment of the low likelihood of PDVSA curing the defaults, we fully reserved $48 million of accounts receivable from PDVSA in the first quarter of 2009. In addition, we ceased revenue recognition of these operations in the first quarter of 2009 as we no longer believed that the collectability of revenues was reasonably assured. This indicator of impairment required us to review our Venezuela property, plant and equipment for recoverability, which resulted in recording a $211 million impairment charge at March 31, 2009. We estimated this impairment charge using probability-weighted discounted cash flow estimates that considered expected cash flows from: (1) the continued operation of the assets considering a complete cure of the default or a partial payment and renegotiation of the contracts, (2) the purchase of the assets by PDVSA, and (3) the results of arbitration with varying degrees of award and collection. Considering the risk associated with operating in Venezuela, we utilized an after-tax discount rate of 20 percent. The use of alternate judgments and/or assumptions would have resulted in the recognition of a different or no impairment charge. Certain deferred charges and credits, which netted to a $30 million charge, were also written off because the related future cash inflows and outflows were no longer expected to occur.

The past due payments from PDVSA triggered technical default of the related project debt under our financing agreements in the fourth quarter of 2008, which resulted in classification of the entire debt balance as current at December 31, 2008.

The summarized results of discontinued operations primarily reflect the results of the above described Venezuela operations in 2009 and 2008 and our former power business in 2007, except where noted otherwise. The summarized assets and liabilities of discontinued operations primarily reflect the above described Venezuela operations. In November 2007, we sold substantially all of our power business for approximately $496 million in cash. In 2008, we received an additional $22 million of proceeds, including the final purchase price adjustments and $8 million from the sale of Hazleton.

Summarized Results of Discontinued Operations

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Revenues	$ —	$ 172	$2,584
Income (loss) from discontinued operations before (impairments) and gain (loss) on sales, gain on deconsolidation, and income taxes	$ (87)	$ 241	$ 454
(Impairments) and gain (loss) on sales	(211)	8	(162)
Gain on deconsolidation	9	—	—
(Provision) benefit for income taxes	66	(124)	(122)
Income (loss) from discontinued operations	$(223)	$ 125	$ 170
Income (loss) from discontinued operations:			
Attributable to noncontrolling interests	$ (70)	$ 13	$ 9
Attributable to The Williams Companies, Inc.	$(153)	$ 112	$ 161

Income (loss) from discontinued operations before (impairments) and gain (loss) on sales, gain on deconsolidation, and income taxes for 2009 primarily includes losses related to our discontinued Venezuela operations, including the previously discussed $48 million of bad debt expense related to fully reserving accounts receivable from PDVSA and the $30 million net charge related to the write-off of certain deferred charges and credits. Offsetting these losses is a $15 million gain related to our former coal operations.

Income (loss) from discontinued operations before (impairments) and gain (loss) on sales, gain on deconsolidation, and income taxes for 2008 includes:

- $140 million of gains related to the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations;
- $77 million of income related to our discontinued Venezuela operations;
- $54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank;
- An $11 million charge associated with an oil purchase contract related to our former Alaska refinery;
- A $10 million charge associated with a settlement primarily related to the sale of NGL pipeline systems in 2002.

Income (loss) from discontinued operations before (impairments) and gain (loss) on sales, gain on deconsolidation, and income taxes for 2007 includes a gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive loss* to earnings in second-quarter 2007. This reclassification was based on the determination that the hedged forecasted transactions were probable of not occurring due to the sale of our power business. This gain is partially offset by unrealized mark-to-market losses of approximately $23 million. *Income (loss) from discontinued operations before (impairments) and gain (loss) on sales, gain on deconsolidation, and income taxes* also includes the results of our former power business and discontinued Venezuela operations.

(Impairments) and gain (loss) on sales for 2009 reflects the previously described $211 million impairment of our Venezuela property, plant, and equipment.

(Impairments) and gain (loss) on sales for 2008 includes the final proceeds from the sale of our former power business.

(Impairments) and gain (loss) on sales for 2007 includes a pre-tax loss of $37 million on the sale of substantially all of our power business. We also recognized impairments of $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception and, accordingly, were no longer recording at fair value, and $14 million related to Hazleton. These impairments were based on our comparison of the carrying value to the estimate of fair value less cost to sell.

(Provision) benefit for income taxes for 2009 includes a $76 million benefit from the reversal of deferred tax balances related to our discontinued Venezuela operations.

Summarized Assets and Liabilities of Discontinued Operations

	December 31,	
	2009	2008
	(Millions)	
Cash and cash equivalents	$—	$ 1
Accounts receivable — net	1	62
Other current assets	—	79
Total current assets	1	142
Property, plant and equipment — net	—	324
Other noncurrent assets	—	63
Total noncurrent assets	—	387
Total assets	$ 1	$529
Long-term debt due within one year	$—	$177
Other current liabilities	—	40
Total current liabilities	—	217
Total noncurrent liabilities	—	82
Total liabilities	$—	$299

Note 3. Investing Activities

Investing Income

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Equity earnings*	$136	$137	$137
Income (loss) from investments*	(75)	1	—
Impairment of cost-based investments	(22)	(4)	(1)
Interest income and other	7	55	116
Total investing income	$ 46	$189	$252

* Items also included in *segment profit (loss).* (See Note 18.)

Income (loss) from investments in 2009 reflects a $75 million impairment charge related to an other-than-temporary loss in value associated with our Venezuelan investment in Accroven SRL (Accroven). Accroven owns and operates gas processing facilities and a NGL fractionation plant for the exclusive benefit of PDVSA. The deteriorating circumstances in the first quarter of 2009 for our Venezuelan operations (see Note 2) caused us to review our investment in Accroven. We utilized a probability-weighted discounted cash flow analysis, which included an after-tax discount rate of 20 percent to reflect the risk associated with operating in Venezuela. (See Note 14.) Accroven was not part of the operations that were expropriated by the Venezuelan government in May 2009. We have been engaged in discussions regarding the eventual disposition of Accroven.

Impairment of cost-based investments in 2009 includes an $11 million impairment related to our 4 percent interest in a Venezuelan corporation that owns and operates oil and gas activities. This investment resulted from our previous 10 percent direct working interest in a concession that was converted to a reduced interest in a mixed company at the direction of the Venezuelan government in 2006. Considering our evaluation of the deteriorating financial condition of this corporation, we recorded an other-than-temporary decline in value of our remaining investment balance.

The unfavorable change in *interest income and other* in 2009 and 2008 is primarily due to lower average interest rates.

Investments

	December 31, 2009	December 31, 2008
	(Millions)	
Equity method:		
Gulfstream — 50%	$383	$525
Discovery Producer Services LLC — 60%*	189	184
Laurel Mountain Midstream, LLC — 51%*	133	—
Petrolera Entre Lomas S.A. — 40.8%	81	73
Accroven — 49.3%	—	69
Other	98	96
	884	947
Cost method	2	24
	$886	$971

* We account for these investments under the equity method due to the significant participatory rights of our partners such that we do not control the investments.

Differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees are primarily related to impairments we previously recognized.

In 2009, we invested $132 million in Laurel Mountain Midstream, LLC. In addition, we contributed $20 million in 2009 and $90 million in 2008 to Gulfstream.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $291 million in 2009 and $167 million in 2008. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	2009	2008
	(Millions)	
Gulfstream	$223	$58
Discovery Producer Services LLC	32	56
Aux Sable Liquid Products LP	15	28

In 2009, we received a $148 million distribution from Gulfstream following its debt offering.

Summarized Financial Position and Results of Operations of Equity Method Investments

	December 31,	
	2009	2008
	(Millions)	
Current assets	$ 383	$ 342
Noncurrent assets	3,723	3,505
Current liabilities	266	253
Noncurrent liabilities	1,511	1,278

	Years Ended December 31,		
	2009	2008	2007
		(Millions)	
Gross revenue	$1,115	$1,246	$1,163
Operating income	516	521	515
Net income	396	405	385

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses reflected in *other (income) expense — net* within *segment costs and expenses.*

	Years Ended December 31, 2009	2008 (Millions)	2007
Exploration & Production			
Gain on sale of contractual right to an international production payment	$ —	$(148)	$ —
Impairment of certain properties	20	143	—
Penalties from early release of drilling rigs	32	—	—
Gas Pipeline			
Income from change in estimate related to a regulatory liability	—	—	(17)
Income from payments received for a terminated firm transportation agreement on Grays Harbor lateral	—	—	(18)
Gain on sale of certain south Texas assets	—	(10)	—
Midstream			
Income from favorable litigation outcome	—	—	(12)
Impairment of Carbonate Trend pipeline	—	6	10
Gulf Liquids litigation contingency accrual reversal (see Note 16)	—	(32)	—
Involuntary conversion gains related to Ignacio plant	(4)	(12)	—
Gain on sale of Cameron Meadows plant	(40)	—	—
Gas Marketing Services			
Accrual for litigation contingencies	—	—	20

Other (income) expense — net within *segment costs and expenses* also includes net foreign currency exchange gains of $38 million in 2008 and net foreign currency exchange losses of $12 million in 2007. The net gain in 2008 primarily relates to the remeasurement of current assets held in U.S. dollars within our Canadian operations in the Midstream segment.

Impairment of certain Exploration & Production properties

Based on a comparison of the estimated fair value to the carrying value, Exploration & Production recorded a $15 million impairment in December 2009 related to costs of acquired unproved reserves resulting from a 2008 acquisition in the Fort Worth basin. Additionally, Exploration & Production recorded impairment charges of $5 million and $143 million in 2009 and 2008, respectively, related to properties in the Arkoma basin. Our impairment analysis included an assessment of undiscounted (except for the unproved reserves) and discounted future cash flows, which considered information obtained from drilling, other activities, and year-end natural gas reserve quantities.

Additional Items

In 2009, Exploration & Production recognized $11 million of income related to the recovery of certain royalty overpayments from prior periods, which is reflected within *revenues.*

In 2008, Exploration & Production recorded a $34 million accrual for Wyoming severance taxes, which is reflected in *costs and operating expenses* within *segment costs and expenses.* Associated with this charge is an interest expense accrual of $4 million, which is included in *interest accrued.* (See Note 16.)

Note 5. Provision for Income Taxes

The *provision for income taxes* from continuing operations includes:

	2009	2008	2007
		(Millions)	
Current:			
Federal	$ 10	$179	$ 29
State	12	24	9
Foreign	21	8	21
	43	211	59
Deferred:			
Federal	271	466	422
State	42	(11)	(4)
Foreign	3	11	13
	316	466	431
Total provision	$359	$677	$490

Reconciliations from the *provision for income taxes* from continuing operations at the federal statutory rate to the realized *provision for income taxes* are as follows:

	2009	2008	2007
		(Millions)	
Provision at statutory rate	$330	$750	$490
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	35	8	4
Foreign operations — net	25	(16)	1
Impact of nontaxable noncontrolling interests	(49)	(54)	(25)
Other — net	18	(11)	20
Provision for income taxes	$359	$677	$490

State income taxes (net of federal benefit) were reduced by $46 million in 2008 due to a reduction in our estimate of the effective deferred state rate reflective of a change in the mix of jurisdictional attribution of taxable income.

Income from continuing operations before income taxes includes $36 million of foreign loss, and $139 million and $127 million of foreign income in 2009, 2008, and 2007, respectively.

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various filing positions, we apply the two-step process of recognition and measurement. In association with this liability, we record an estimate of related interest and tax exposure as a component of our tax provision. The impact of this accrual is included within *other — net* in our reconciliation of the tax provision to the federal statutory rate.

Significant components of *deferred tax liabilities* and *deferred tax assets* as of December 31, 2009 and 2008, are as follows:

	2009	2008
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$3,658	$3,288
Derivatives — net	66	263
Investments	491	380
Other	108	112
Total deferred tax liabilities	4,323	4,043
Deferred tax assets:		
Accrued liabilities	557	581
Foreign carryovers	4	3
Minimum tax credits	62	—
Other	58	55
Total deferred tax assets	681	639
Less valuation allowance	4	3
Net deferred tax assets	677	636
Overall net deferred tax liabilities	$3,646	$3,407

The *valuation allowance* at December 31, 2009 and 2008 serves to reduce the recognized tax benefit associated with foreign carryovers to an amount that will, more likely than not, be realized. We do not expect to be able to utilize our $4 million of foreign deferred tax assets.

Undistributed earnings of certain consolidated foreign subsidiaries, inclusive of discontinued operations, at December 31, 2009, totaled approximately $165 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in foreign operations.

Cash payments for income taxes (net of refunds and including discontinued operations) were $14 million, $155 million, and $384 million in 2009, 2008, and 2007, respectively. Cash tax payments include settlements with taxing authorities associated with prior period audits of $9 million, $47 million, and $94 million in 2009, 2008, and 2007, respectively.

As of December 31, 2009, we had approximately $72 million of unrecognized tax benefits. If recognized, approximately $61 million, net of federal tax expense, would be recorded as a reduction of income tax expense. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2009	2008
	(Millions)	
Balance at beginning of period	$79	$76
Additions based on tax positions related to the current year	—	3
Additions for tax positions for prior years	4	8
Reductions for tax positions of prior years	(7)	(8)
Settlement with taxing authorities	(4)	—
Balance at end of period	$72	$79

We recognize related interest and penalties as a component of income tax expense. Total interest and penalties recognized as part of income tax expense were $17 million, $2 million, and $60 million for 2009, 2008, and 2007, respectively. Approximately $93 million and $81 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2009 and 2008, respectively.

As of December 31, 2009, the Internal Revenue Service (IRS) examination of our consolidated U.S. income tax return for 2008 is in process. IRS examinations for 1997 through 2007 have been completed at the field level but the years remain open for certain unagreed issues. The statute of limitations for most states expires one year after expiration of the IRS statute.

Generally, tax returns for our Venezuelan, Argentine, and Canadian entities are open to audit from 2002 through 2009. Certain Canadian entities are currently under examination.

During the next 12 months, we do not expect ultimate resolution of any uncertain tax position associated with a domestic or international matter will result in a significant increase or decrease of our unrecognized tax benefit. However, certain matters we have contested to the Internal Revenue Service Appeals Division could be resolved and result in a reduction to our unrecognized tax benefit.

Note 6. Earnings Per Common Share from Continuing Operations

	Years Ended December 31,		
	2009	2008	2007
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income from continuing operations attributable to The Williams Companies, Inc., available to common stockholders for basic and diluted earnings per common share(1)	$ 438	$ 1,306	$ 829
Basic weighted-average shares(2)(3)	581,674	581,342	596,174
Effect of dilutive securities:			
Nonvested restricted stock units	2,216	1,334	1,627
Stock options	2,065	3,439	4,743
Convertible debentures(3)	3,430	6,604	7,322
Diluted weighted-average shares	589,385	592,719	609,866
Earnings per common share from continuing operations:			
Basic	$ .75	$ 2.25	$ 1.39
Diluted	$ .75	$ 2.21	$ 1.37

(1) The years of 2009, 2008, and 2007 include $1 million, $2 million and $3 million, respectively, of interest expense, net of tax, associated with our 5.5 percent convertible debentures. (See Note 12.) These amounts have been added back to *income from continuing operations attributable to The Williams Companies, Inc., available to common stockholders* to calculate diluted earnings per common share.

(2) From the inception of our stock repurchase program in third-quarter 2007 to its completion in July 2008, we purchased 29 million shares of our common stock. (See Note 12.)

(3) During 2009 and 2008, we issued 3 million shares and 2 million shares, respectively, of our common stock in exchange for a portion of our 5.5 percent convertible debentures. (See Note 12.)

The table below includes information related to stock options that were outstanding at the end of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the fourth quarter weighted-average market price of our common shares.

	2009	2008	2007
Options excluded (millions)	3.7	6.4	.8
Weighted-average exercise prices of options excluded	$ 30.21	$ 26.41	$ 40.07
Exercise price ranges of options excluded	$20.28 - $42.29	$16.40 - $42.29	$36.66 - $42.29
Fourth quarter weighted-average market price	$ 19.81	$ 16.37	$ 35.14

Note 7. Employee Benefit Plans

We have noncontributory defined benefit pension plans in which all eligible employees participate. Currently, eligible employees earn benefits primarily based on a cash balance formula. Various other formulas, as defined in the plan documents, are utilized to calculate the retirement benefits for plan participants not covered by the cash balance formula. At the time of retirement, participants may elect, to the extent they are eligible for the various options, to receive annuity payments, a lump sum payment, or a combination of lump sum and annuity payments. In addition to our pension plans, we currently provide subsidized retiree medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for the subsidized retiree medical benefits, except for participants that were employees of Transco Energy Company on December 31, 1995, and other miscellaneous defined participant groups. Certain of these other postretirement benefit plans, particularly the subsidized retiree medical benefit plans, provide for retiree contributions and contain other cost-sharing features such as deductibles, co-payments, and co-insurance. The accounting for these plans anticipates future cost-sharing that is consistent with our expressed intent to increase the retiree contribution level generally in line with health care cost increases.

Benefit Obligations

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. The annual measurement date for our plans is December 31.

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$1,035	$ 896	$ 273	$ 284
Service cost	32	23	2	2
Interest cost	62	60	16	18
Plan participants' contributions	—	—	5	5
Benefits paid	(59)	(70)	(24)	(23)
Medicare Part D subsidy	—	—	2	2
Plan amendment	—	—	(18)	(38)
Actuarial loss	48	126	3	23
Benefit obligation at end of year	1,118	1,035	259	273
Change in plan assets:				
Fair value of plan assets at beginning of year	705	1,074	126	192
Actual return on plan assets	153	(360)	25	(62)
Employer contributions	61	61	16	14
Plan participants' contributions	—	—	5	5
Benefits paid	(59)	(70)	(24)	(23)
Fair value of plan assets at end of year	860	705	148	126
Funded status — underfunded	$ (258)	$ (330)	$(111)	$(147)
Accumulated benefit obligation	$1,075	$ 959		

The underfunded status of our pension plans and other postretirement benefit plans presented in the previous table are recognized in the Consolidated Balance Sheet within the following accounts:

	December 31,	
	2009	2008
	(Millions)	
Underfunded pension plans:		
Current liabilities	$ 1	$ 1
Noncurrent liabilities	257	329
Underfunded other postretirement benefit plans:		
Current liabilities	8	8
Noncurrent liabilities	103	139

The plan assets within our other postretirement benefit plans are intended to be used for the payment of benefits for certain groups of participants. The *current liabilities* for the other postretirement benefit plans represent the current portion of benefits expected to be payable in the subsequent year for the groups of participants whose benefits are not expected to be paid from plan assets.

The 2009 benefit obligation *actuarial loss* of $48 million for our pension plans is primarily due to the impact of decreases in the discount rate utilized to calculate the benefit obligation. The 2008 benefit obligation *actuarial losses* of $126 million for our pension plans and $23 million for our other postretirement benefit plans are primarily due to the impact of decreases in the discount rate utilized to calculate the benefit obligation as well as changes to the mortality assumptions. The other postretirement benefits *plan amendments* of $18 million in 2009 and $38 million in 2008 are due to consecutive increases in the retirees' cost-sharing percentage within our subsidized retiree medical benefit plans.

At December 31, 2009 and 2008, all of our pension plans had a projected benefit obligation and accumulated benefit obligation in excess of plan assets.

The current accounting rules for the determination of *net periodic benefit expense* allow for the delayed recognition of gains and losses caused by differences between actual and assumed outcomes for items such as estimated return on plan assets, or caused by changes in assumptions for items such as discount rates or estimated future compensation levels. The *net actuarial gain (loss)* presented in the following table and recorded in *accumulated other comprehensive loss* and *net regulatory assets* represents the cumulative net deferred gain (loss) from these types of differences or changes which have not yet been recognized in the Consolidated Statement of Income. A portion of the *net actuarial gain (loss)* is amortized over the participants' average remaining future years of service, which is approximately 13 years for our pension plans and approximately 12 years for our other postretirement benefit plans.

Pre-tax amounts not yet recognized in *net periodic benefit expense* at December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2009	**2008**	**2009**	**2008**
	(Millions)			
Amounts included in *accumulated other comprehensive loss*:				
Prior service (cost) credit	$ (4)	$ (5)	$ 15	$ 12
Net actuarial loss	(621)	(708)	(9)	(8)
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:				
Prior service credit	N/A	N/A	$ 28	$ 24
Net actuarial loss	N/A	N/A	(40)	(57)

Net Periodic Benefit Expense and Items Recognized in Other Comprehensive Income (Loss)

Net periodic benefit expense and other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)* before taxes for the years ended December 31 consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
	(Millions)					
Components of net periodic benefit expense:						
Service cost	$ 32	$ 23	$ 23	$ 2	$ 2	$ 3
Interest cost	62	60	54	16	18	17
Expected return on plan assets	(61)	(79)	(73)	(9)	(13)	(12)
Amortization of prior service cost (credit)	1	1	—	(11)	—	—
Amortization of net actuarial loss	43	13	19	3	—	—
Amortization of regulatory asset	1	—	1	5	5	5
Net periodic benefit expense	$ 78	$ 18	$ 24	$ 6	$ 12	$ 13
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss):*						
Net actuarial (gain) loss	$(44)	$565	$(68)	$ 1	$ 15	$(15)
Prior service credit	—	—	—	(7)	(16)	—
Amortization of prior service (cost) credit	(1)	(1)	—	4	(1)	(2)
Amortization of net actuarial loss	(43)	(13)	(19)	—	—	—
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*	(88)	551	(87)	(2)	(2)	(17)
Total recognized in *net periodic benefit expense* and *other comprehensive income (loss)*	$(10)	$569	$(63)	$ 4	$ 10	$ (4)

Other changes in plan assets and benefit obligations for our other postretirement benefit plans associated with our FERC-regulated gas pipelines are recognized in *net regulatory assets* at December 31, 2009, and include *net actuarial gain* of $14 million, *prior service credit* of $11 million, *amortization of prior service credit* of $7 million, and *amortization of net actuarial loss* of $3 million. At December 31, 2008, amounts recognized in *net regulatory assets* included *net actuarial loss* of $83 million, *prior service credit* of $22 million, and *amortization of prior service credit* of $1 million. At December 31, 2007, amounts recognized in *net regulatory liabilities* included *net actuarial gain* of $18 million and *amortization of prior service credit* of $2 million.

Pre-tax amounts expected to be amortized in *net periodic benefit expense* in 2010 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in *accumulated other comprehensive loss*:		
Prior service cost (credit)	$ 1	$ (5)
Net actuarial loss	34	—
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:		
Prior service credit	N/A	$ (9)
Net actuarial loss	N/A	2

The differences in the amount of actuarially determined *net periodic benefit expense* for our other postretirement benefit plans and the other postretirement benefit costs recovered in rates for our FERC-regulated gas pipelines are deferred as a regulatory asset or liability. At December 31, 2009, we have *net regulatory liabilities* of $3 million and at December 31, 2008, we had *net regulatory assets* of $26 million related to these deferrals. These amounts will be reflected in future rates based on the gas pipelines' rate structures.

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	5.78%	6.08%	5.80%	6.00%
Rate of compensation increase	5.00	5.00	N/A	N/A

The weighted-average assumptions utilized to determine *net periodic benefit expense* for the years ended December 31 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2009	2008	2007	2009	2008	2007
Discount rate	6.08%	6.41%	5.80%	6.00%	6.40%	5.80%
Expected long-term rate of return on plan assets	7.75	7.75	7.75	7.00	7.00	6.97
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans. The year-end discount rates were determined considering a yield curve comprised of high-quality corporate bonds published by a large securities firm and the timing of the expected benefit cash flows of each plan.

The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' Investment Policy Statement, and capital market projections for the asset classifications in which the portfolio is invested and the target weightings of each asset classification.

The expected return on plan assets component of *net periodic benefit expense* is calculated using the market-related value of plan assets. For assets held in our pension plans, the market-related value of plan assets is equal to the fair value of plan assets adjusted to reflect amortization of gains or losses associated with the difference between the expected return on plan assets and the actual return on plan assets over a five-year period. Additionally, the market-related value of plan assets may be no more than 110 percent or less than 90 percent of the fair value of plan assets at the beginning of the year. The market-related value of plan assets for our other postretirement benefit plans is equal to the unadjusted fair value of plan assets at the beginning of the year.

The mortality assumptions used to determine the obligations for our pension and other postretirement benefit plans are related to the experience of the plans and the best estimate of expected plan mortality. The selected mortality tables are among the most recent tables available.

The assumed health care cost trend rate for 2010 is 8.2 percent, and systematically decreases to 5.0 percent by 2020. The health care cost trend rate assumption has a significant effect on the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Point increase	Point decrease
	(Millions)	
Effect on total of service and interest cost components	$ 2	$ (2)
Effect on other postretirement benefit obligation	33	(27)

Plan Assets

The investment policy for our pension and other postretirement benefit plans articulates an investment philosophy in accordance with ERISA, which governs the investment of the assets in a diversified portfolio. The investment strategy for the assets of the pension plans and approximately one half of the assets of the other postretirement benefit plans include maximizing returns with reasonable and prudent levels of risk. The investment returns on the approximate one half of remaining assets of the other postretirement benefit plans is subject to federal income tax; therefore, the investment strategy also includes investing in a tax efficient manner. The target allocation ranges at December 31, 2009, for the pension plan assets were 65 percent to 90 percent equity securities, which includes commingled investment funds, and 10 percent to 30 percent debt securities and cash management.

The assets are invested in accordance with the target allocations identified previously. Additional target allocation ranges are identified for U.S. equities and non-U.S. equities. The target allocation ranges at December 31, 2009, were a minimum of 45 percent and a maximum of 70 percent for U.S. equities and a minimum of 20 percent and a maximum of 45 percent for non-U.S. equities. The asset allocation ranges established by the investment policy are based upon a long-term investment perspective. The ranges are weighted toward equity securities since the liabilities of the pension and other postretirement benefit plans are long-term in nature and historically equity securities have outperformed other asset classes over long periods of time.

Equity security investments are restricted to high-quality, readily marketable securities that are actively traded on the major U.S. and foreign national exchanges. Investment in Williams' securities or an entity in which Williams has a majority ownership is prohibited in the pension plans except where these securities may be owned in a commingled investment fund in which the plans' trusts invest. No more than 5 percent of the total stock portfolio valued at market may be invested in the common stock of any one corporation. No more than 25 percent of stock valued at market may be held in any one industry category. No more than 10 percent of the total capitalization of any one issuer shall be held in the total stock portfolio. The following securities and transactions are not authorized: unregistered securities, commodities or commodity contracts, short sales or margin transactions, or other leveraging strategies. Investment strategies using the direct holding of options or futures require approval and, historically, have not been used; however, these instruments may be used in commingled investment funds.

Fixed income securities are restricted to high-quality, marketable securities that include U.S. Treasuries, U.S. government guaranteed and nonguaranteed mortgage-backed securities, government and municipal bonds, and investment grade corporate issues. The overall rating of the debt security assets is required to be at least "A," according to the Moody's or Standard & Poor's rating systems. No more than 5 percent of the total portfolio at the time of purchase may be invested in the debt securities of any one issuer with the exception of U.S. government guaranteed and agency securities.

During 2009, ten active investment managers and one passive investment manager managed substantially all of the pension plans' funds and five active investment managers managed the other postretirement benefit plans' funds. Each of the managers had responsibility for managing a specific portion of these assets and each investment manager was responsible for 2 percent to 17 percent of the assets.

We believe the pension and other postretirement benefit plans have no significant concentrations of risk because of the diversity of the types of investments, diversity of the various industries, and the diversity of the fund managers and investment strategies. Generally, the investments in the plan are publicly traded, therefore, minimizing liquidity risk in the portfolio.

The pension and other postretirement benefit plans participate in securities lending programs under which securities are loaned to selected securities brokerage firms. The title of the securities is transferred to the borrower, but the plans are entitled to all distributions made by the issuer of the securities during the term of the loan and retain the right to redeem the securities on short notice. All loans require collateralization by U.S. government securities, cash, or letters of credit that equal at least 102 percent of the fair value of the loaned securities plus accrued interest. There are limitations on the aggregate fair value of securities that may be loaned to any one broker and to all brokers as a group. The collateral is invested in repurchase agreements, asset-backed securities, bank notes, corporate floating rate notes, and certificates of deposit. At December 31, 2009, the fair values of the loaned securities are $63 million for the pension plans and $9 million for the other postretirement benefit plans and are included in the following tables. At December 31, 2009, the fair values of securities held as collateral, and the obligation to return the collateral, are $66 million for the pension plans and $9 million for the other postretirement benefit plans and are not included in the following tables.

The fair values (see Note 14) of our pension plan assets at December 31, 2009, by asset category are as follows:

	Level 1	Level 2	Level 3	Total
		(Millions)		
Pension assets:				
Cash management fund(1)	$ 23	$ —	$—	$ 23
Equity securities:				
U.S. large cap	244	—	—	244
U.S. small cap	103	—	—	103
International developed markets large cap growth	2	58	—	60
Emerging markets growth	10	9	—	19
Commingled investment funds:				
U.S. large cap(2)	—	84	—	84
Emerging markets value(3)	—	29	—	29
International developed markets large cap value(4)	—	74	—	74
Fixed income securities(5):				
U.S. treasuries	11	3	—	14
Mortgage-backed securities	—	53	—	53
Corporate bonds	—	149	—	149
Insurance company investment contracts and other	—	8	—	8
Total assets at fair value	$393	$467	$—	$860

The fair values of our other postretirement benefits plan assets at December 31, 2009, by asset category are as follows:

	Level 1	Level 2	Level 3	Total
		(Millions)		
Other postretirement benefit assets:				
Cash management funds(1)	$15	$—	$—	$ 15
Equity securities:				
U.S. large cap	49	—	—	49
U.S. small cap	19	—	—	19
International developed markets large cap growth	—	13	—	13
Emerging markets growth	2	2	—	4
Commingled investment funds:				
U.S. large cap(2)	—	8	—	8
Emerging markets value(3)	—	3	—	3
International developed markets large cap value(4)	—	7	—	7
Fixed income securities(6):				
U.S. treasuries	1	—	—	1
Government and municipal bonds	—	8	—	8
Mortgage-backed securities	—	6	—	6
Corporate bonds	—	15	—	15
Total assets at fair value	$86	$62	$—	$148

(1) These funds invest in high credit-quality, short-term corporate, and government money market debt securities that have remaining maturities of approximately one year or less, and are deemed to have minimal credit risk.

(2) This fund invests primarily in equity securities comprising the Standard & Poor's 500 Index. The investment objective of the fund is to match the return of the Standard & Poor's 500 Index. There are certain restrictions that limit the amount that can be withdrawn from the fund to 4 percent per month of the plans' total net asset value in the fund. If the plans do not withdraw the percentage allowed in a month, the plans accumulate the right to redeem the percentage not withdrawn in future months. As of December 31, 2009, 37 percent was eligible for withdrawal.

(3) This fund invests in equity securities of international emerging markets for the purpose of capital appreciation. The fund invests primarily in common stocks of the financial, telecommunications, consumer goods, energy, industrial, materials, and utilities sectors, as well as forward foreign currency exchange contracts.

(4) This fund invests in a diversified portfolio of international equity securities for the purpose of capital appreciation. The fund invests primarily in common stock of the consumer goods, materials, financial, energy, information technology, telecommunications, industrial, utilities, and health care sectors, as well as forward foreign currency exchange contracts.

(5) The weighted-average credit quality rating of the pension assets fixed income security portfolio is investment grade with a weighted-average duration of 5.1 years.

(6) The weighted-average credit quality rating of the other postretirement benefit assets fixed income security portfolio is investment grade with a weighted-average duration of 4.5 years.

The asset's fair value measurement level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Shares of the cash management funds are valued at fair value based on published market prices as of the close of business on the last business day of the year, which represents the net asset values of the shares held.

The fair values of equity securities traded on U.S. exchanges are derived from quoted market prices as of the close of business on the last business day of the year. The fair values of equity securities traded on foreign exchanges are also derived from quoted market prices as of the close of business on an active foreign exchange on the last business day of the year. However, the valuation requires translation of the foreign currency to U.S. dollars and this translation is considered an observable input to the valuation.

The fair value of all commingled investment funds has been estimated based on the net asset values per unit of each of the funds. The net asset values per unit of the fund represent the aggregate value of the fund's assets less liabilities, divided by the number of units outstanding. Common stocks traded in active markets comprise the majority of each commingled investment fund's assets. The fair value of these common stocks is derived from quoted market prices as of the close of business on the last business day of the year.

The fair value of fixed income securities, except U.S. treasury notes and bonds, are determined using pricing models. These pricing models incorporate observable inputs such as benchmark yields, reported trades, broker/dealer quotes, and issuer spreads for similar securities to determine fair value. The treasury notes and bonds are valued at fair value based on closing prices on the last business day of the year reported in the active market in which the security is traded.

The investment contracts with insurance companies are valued at fair value by discounting the cash flow of a bond using a yield to maturity based on an investment grade index or comparable index with a similar maturity value, maturity period, and nominal coupon rate.

The following table presents the weighted-average asset allocations at December 31, 2008, by asset category.

	Pension Benefits	Other Postretirement Benefits
Equity securities	78%	71%
Debt securities	17	17
Other	5	12
	100%	100%

Equity securities include investments in commingled investment funds that invest entirely in equity securities and comprise 24 percent of the pension plans' weighted-average assets and 13 percent of the other postretirement benefit plans' weighted-average assets at December 31, 2008.

Plan Benefit Payments and Employer Contributions

Following are the expected benefits to be paid by the plans and the expected federal prescription drug subsidy to be received in the next ten years. These estimates are based on the same assumptions previously discussed and reflect future service as appropriate. The actuarial assumptions are based on long-term expectations and include, but are not limited to, assumptions as to average expected retirement age and form of benefit payment. Actual benefit payments could differ significantly from expected benefit payments if near-term participant behaviors differ significantly from the actuarial assumptions.

	Pension Benefits	Other Postretirement Benefits	Federal Prescription Drug Subsidy
		(Millions)	
2010	$ 44	$18	$ (2)
2011	44	18	(3)
2012	51	18	(3)
2013	52	18	(3)
2014	66	18	(3)
2015-2019	466	99	(19)

In 2010, we expect to contribute approximately $60 million to our tax-qualified pension plans and approximately $1 million to our nonqualified pension plans, for a total of approximately $61 million, and approximately $16 million to our other postretirement benefit plans.

Defined Contribution Plans

We also maintain defined contribution plans for the benefit of substantially all of our employees. Generally, plan participants may contribute a portion of their compensation on a pre-tax and after-tax basis in accordance with the plans' guidelines. We match employees' contributions up to certain limits. Our matching contributions charged to expense were $25 million in 2009, $24 million in 2008, and $22 million in 2007. A fund within one of our defined contribution plans is a nonleveraged employee stock ownership plan (ESOP). The shares held by the ESOP are treated as outstanding when computing earnings per share and the dividends on the shares held by the ESOP are recorded as a component of retained earnings. There were no contributions in 2009, 2008, and 2007 to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock are no longer allowed within this defined contribution plan.

Note 8. Inventories

	December 31, 2009	December 31, 2008
	(Millions)	
Natural gas liquids and olefins	$ 70	$ 56
Natural gas in underground storage	47	97
Materials, supplies and other	105	107
	$222	$260

Inventories are primarily determined using the average-cost method.

Note 9. Property, Plant and Equipment

	Estimated Useful Life (a) (Years)	Depreciation Rates (a) (%)	December 31, 2009	December 31, 2008
			(Millions)	
Nonregulated:				
Oil and gas properties	(b)		$ 9,854	$ 8,507
Natural gas gathering and processing facilities	5 - 40		5,461	4,823
Construction in progress	(c)		1,227	1,411
Other	2 - 45		816	765
Regulated:				
Natural gas transmission facilities		.01 - 7.25	8,814	8,441
Construction in progress		(c)	152	120
Other		.01 - 50	1,301	1,293
Total property, plant and equipment, at cost			27,625	25,360
Accumulated depreciation, depletion & amortization			(8,981)	(7,619)
Property, plant and equipment — net			$18,644	$17,741

(a) Estimated useful life and depreciation rates are presented as of December 31, 2009. Depreciation rates for regulated assets are prescribed by the FERC.

(b) Oil and gas properties are depleted using the units-of-production method. See Note 1 of Notes to Consolidated Financial Statements for more information. Balances include $704 million at December 31, 2009, and $571 million at December 31, 2008, of capitalized costs related to properties with unproved reserves not yet subject to depletion at Exploration & Production.

(c) Construction in progress balances not yet subject to depreciation and depletion.

Depreciation, depletion and amortization expense for *property, plant and equipment — net* was $1.5 billion in 2009, $1.3 billion in 2008, and $1.0 billion in 2007. Our fourth-quarter depletion includes an unfavorable adjustment of $17 million. This adjustment was primarily the result of new oil and gas accounting guidance (Accounting Standards Update 2010-03) that requires we value our reserves using an average price. This price is calculated using prices at the beginning of the month for the preceding 12 months. This accounting guidance has been adopted on a prospective basis beginning in the fourth quarter of 2009.

Regulated *property, plant and equipment — net* includes $946 million and $985 million at December 31, 2009 and 2008, respectively, related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of our prior acquisitions. This amount is being amortized over 40 years using the straight-line amortization method. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

Asset Retirement Obligations

Our accrued obligations relate to producing wells, underground storage caverns, offshore platforms, fractionation facilities, gas gathering well connections and pipelines, and gas transmission facilities. At the end of the useful life of each respective asset, we are legally obligated to plug both producing wells and storage caverns and remove any related surface equipment, to restore land and remove surface equipment at fractionation facilities, to dismantle offshore platforms, to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment, and to remove certain components of gas transmission facilities from the ground.

The following table presents the significant changes to our asset retirement obligations, of which $716 million and $630 million are included in *other liabilities and deferred income*, with the remaining current portion in *accrued liabilities* at December 31, 2009 and 2008, respectively.

	December 31, 2009	December 31, 2008
	(Millions)	
Beginning balance	$644	$399
Liabilities settled	(13)	(11)
Additions	32	59
Accretion expense	51	64
Revisions	14	133
	$728	$644

Pursuant to its 2008 rate case settlement, Transco deposits a portion of its collected rates into an external trust (ARO Trust) that is specifically designated to fund future asset retirement obligations. Transco is also required to make annual deposits into the trust through 2012. The trust is reported as a component of *other assets and deferred charges* and has a carrying value of $22 million and $13 million as of December 31, 2009 and 2008, respectively.

Property Insurance Changes

As a result of damage caused by recent hurricanes, the availability of named windstorm insurance has been significantly reduced. Additionally, named windstorm insurance coverage that is available for offshore assets comes at significantly higher premium amounts, higher deductibles and lower coverage limits. Considering these changes, we have reduced the overall named windstorm property insurance coverage for our assets in the Gulf of Mexico area beginning in the second quarter of 2009. In addition, certain assets are no longer covered for named windstorm losses, primarily certain offshore lateral pipelines.

Note 10. Accounts Payable and Accrued Liabilities

Under our cash-management system, certain cash accounts reflected negative balances to the extent checks written have not been presented for payment. These negative balances represent obligations and have been reclassified to *accounts payable. Accounts payable* includes $44 million of these negative balances at December 31, 2009 and $95 million at December 31, 2008.

Accrued Liabilities

	December 31, 2009	December 31, 2008
	(Millions)	
Interest on debt	$199	$ 179
Taxes other than income taxes	176	221
Employee costs	158	167
Income taxes	112	144
Other, including other loss contingencies	303	428
	$948	$1,139

Note 11. Debt, Leases and Banking Arrangements

In February 2010, we completed a strategic restructuring that impacted our long-term debt and credit facilities. See Note 19 for further discussion.

Long-Term Debt

	Weighted-Average Interest Rate(1)	December 31, 2009(2)	December 31, 2008(2)
		(Millions)	
Secured			
Capital lease obligations	9.5%	$ 3	$ 5
Unsecured			
5.5% to 10.25%, payable through 2033	7.7%	8,023	7,446
Adjustable rate, payable through 2012	1.2%	250	250
Total long-term debt, including current portion		8,276	7,701
Long-term debt due within one year		(17)	(18)
Long-term debt		$8,259	$7,683

(1) At December 31, 2009.

(2) Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, make certain distributions, repurchase equity, and incur additional debt.

Revolving Credit and Letter of Credit Facilities (Credit Facilities)

At December 31, 2009, we have an unsecured, $1.5 billion credit facility with a maturity date of May 1, 2012. Northwest Pipeline and Transco each have access to $400 million under the credit facility to the extent not otherwise utilized by us. We expect that our ability to borrow under the credit facility is reduced by $70 million due to the bankruptcy of a participating bank. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the lender's base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. We are required to pay a commitment fee (currently 0.125 percent) based on the unused portion of the credit facility. The margins and commitment fee are generally based on the specific borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include the following:

- Our ratio of debt to capitalization must be no greater than 65 percent. At December 31, 2009, we are in compliance with this covenant.
- Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco. At December 31, 2009, they are in compliance with this covenant.

We have unsecured credit facilities totaling $700 million, which mature in October 2010. These credit facilities provide for both borrowings and issuing letters of credit but are expected to be used primarily for issuing letters of credit. We are required to pay the funding bank fixed fees at a weighted-average interest rate of 2.29 percent on the total committed amount and interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR.

The funding bank, an affiliate of Citibank N.A., syndicated its associated credit risk through a private offering that allows for the resale of certain restricted securities to qualified institutional buyers. To facilitate the syndication of these credit facilities, the bank established a trust funded by the institutional investors. The assets of the trust serve as collateral to reimburse the bank for our borrowings in the event that the credit facilities are delivered to the investors as described below. Thus, we have no asset securitization or collateral requirements under the credit facilities. Upon the occurrence of certain credit events, letters of credit under the agreement become cash collateralized creating a borrowing under the credit facilities. Concurrently, the funding bank can deliver the credit facilities to the institutional investors, whereby the investors replace the funding bank as lender under the credit facilities. Upon such occurrence, we will pay:

	$700 Million Facilities	
	$500 million	$200 million
Interest Rate	4.35 percent	LIBOR
Facility Fixed Fee	2.29 percent	

In second-quarter 2009, two of our unsecured revolving credit facilities totaling $500 million expired and were not renewed. These facilities were originated primarily in support of our former power business.

At December 31, 2009, WPZ has an unsecured $450 million credit agreement with a maturity date of December 2012. This $450 million credit facility is comprised initially of a $200 million revolving credit facility available for borrowings and letters of credit and a $250 million term loan. WPZ expects that its ability to borrow under this credit facility is reduced by $12 million due to the bankruptcy of a participating bank. Interest on borrowings under this agreement will be payable at rates per annum equal to either (1) a fluctuating base rate equal to the lender's prime rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. At December 31, 2009, WPZ had a $250 million term loan outstanding and no amounts outstanding under the $200 million credit facility. Significant financial covenants under this credit agreement include the following:

- Williams Partners L.P. is required to maintain a ratio of indebtedness to EBITDA (each as defined in the credit agreement) of no greater than 5.0 to 1.0. At December 31, 2009, they are in compliance with this covenant.
- Williams Partners L.P. is required to maintain a ratio of EBITDA to interest expense (as defined in the credit agreement) of not less than 2.75 to 1.0 as of the last day of any fiscal quarter. At December 31, 2009, they are in compliance with this covenant.

At December 31, 2009, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Credit Facilities Expiration	Letters of Credit at December 31, 2009
		(Millions)
$700 million unsecured credit facilities	October 2010	$220
$1.5 billion unsecured credit facility	May 2012	—
$200 million Williams Partners L.P. unsecured credit facility	December 2012	—
		$220

Exploration & Production's Credit Agreement

Exploration & Production has an unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. The agreement extends through December 2013. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Issuances

On March 5, 2009, we issued $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to certain institutional investors in a private debt placement. In August 2009, we completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Aggregate minimum maturities of *long-term debt* (excluding capital leases and unamortized discount and premium) for each of the next five years are as follows:

	(Millions)
2010	$ 15
2011	936
2012	1,203
2013	—
2014	—

Cash payments for interest (net of amounts capitalized), including amounts related to discontinued operations, were as follows: 2009 — $592 million; 2008 — $592 million; and 2007 — $634 million.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2009, are payable as follows:

	(Millions)
2010	$ 48
2011	33
2012	31
2013	27
2014	18
Thereafter	137
Total	$294

Total rent expense was $70 million in 2009, $87 million in 2008 and $68 million in 2007. Rent expense reported in 2007 as discontinued operations, primarily related to a tolling agreement, was $148 million and was offset by approximately $276 million resulting from sales and other transactions made possible by the tolling agreement. This tolling agreement was included in the sale of our power business in 2007. (See Note 2.)

Note 12. Stockholders' Equity

In July 2007, our Board of Directors authorized the repurchase of up to $1 billion of our common stock. During 2007, we purchased 16 million shares for $526 million (including transaction costs) at an average cost of $33.08 per share. During 2008, we purchased 13 million shares of our common stock for $474 million (including transaction costs) at an average cost of $36.76 per share. We completed our $1 billion stock repurchase program in July 2008. Our overall average cost per share was $34.74. This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet.

At December 31, 2009, approximately $25 million of our original $300 million, 5.5 percent junior subordinated convertible debentures, convertible into approximately 2 million shares of common stock, remain outstanding. In 2009 and 2008, we converted $28 million and $27 million, respectively, of the debentures in exchange for 3 million and 2 million shares, respectively, of common stock.

At December 31, 2007, we held all of Williams Partners L.P.'s seven million subordinated units outstanding. In February 2008, these subordinated units were converted into common units of Williams Partners L.P. due to the achievement of certain financial targets that resulted in the early termination of the subordination period. While these subordinated units were outstanding, other issuances of partnership units by Williams Partners L.P. had preferential rights and the proceeds from these issuances in excess of the book basis of assets acquired by Williams Partners L.P. were therefore reflected as *noncontrolling interests in consolidated subsidiaries* on our Consolidated Balance Sheet. Due to the conversion of the subordinated units, these original issuances of partnership units no longer have preferential rights and now represent the lowest level of equity securities issued by Williams Partners L.P. In accordance with our policy regarding the issuance of equity of a consolidated subsidiary, such issuances of nonpreferential equity are accounted for as capital transactions and no gain or loss is recognized. Therefore, as a result of the 2008 conversion, we recognized a decrease to *noncontrolling interests in consolidated subsidiaries* and a corresponding increase to *capital in excess of par value* of approximately $1.2 billion.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, and further amended May 18, 2007, and October 12, 2007, under which each outstanding share of our common stock has a right (as defined in the plan) attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $50 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of our common stock or commences an offer for 15 percent or more of our common stock. The plan contains a mechanism to divest of shares of common stock if such stock in excess of 14.9 percent was acquired inadvertently or without knowledge of the terms of the rights. The rights, which until exercised do not have voting rights, expire in 2014 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of our common stock, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, our common stock having a value equal to two times the exercise price of the right. In the event we are engaged in a merger, business combination, or 50 percent or more of our assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

Note 13. Stock-Based Compensation

Plan Information

On May 17, 2007, our stockholders approved a plan that provides common-stock-based awards to both employees and nonmanagement directors. The plan generally contains terms and provisions consistent with the previous plans. The plan permits the granting of various types of awards including, but not limited to, restricted stock units and stock options and reserves 19 million shares for issuance. At December 31, 2009, 30 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 11 million shares were available for future grants. At December 31, 2008, 33 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 16 million shares were available for future grants.

Additionally, on May 17, 2007, our stockholders approved an Employee Stock Purchase Plan (ESPP) which authorizes up to 2 million shares of our common stock to be available for sale under the plan. The ESPP enables eligible participants to purchase our common stock through payroll deductions not exceeding an annual amount of $15,000 per participant. The ESPP provides for offering periods during which shares may be purchased and continues until the earliest of: (1) the Board of Directors terminates the ESPP, (2) the sale of all shares available under the ESPP, or (3) the tenth anniversary of the date the Plan was approved by the stockholders. The first offering under the ESPP commenced on October 1, 2007 and ended on December 31, 2007. Subsequent offering periods are from January through June and from July through December. Generally, all employees are eligible to participate in the ESPP, with the exception of executives and international employees. The number of shares eligible for an employee to purchase during each offering period is limited to 750 shares. The purchase price of the stock is 85 percent of the lower closing price of either the first or the last day of the offering period. The ESPP requires a one-year holding period before the stock can be sold. Employees purchased 370 thousand shares at an average price of $13.01 per share during 2009. Approximately 1.3 million and 1.7 million shares were available for purchase under the ESPP at December 31, 2009 and 2008, respectively.

Stock Options

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three-year period from the date of grant and can be subject to accelerated vesting if certain future stock prices or specific financial performance targets are achieved. Stock options generally expire ten years after the grant.

The following summary reflects stock option activity and related information for the year ending December 31, 2009.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2008	11.5	$18.10	
Granted	2.1	$10.86	
Exercised	(0.2)	$ 8.46	$ 2
Expired	(0.3)	$33.27	
Forfeited	(0.1)	$22.73	
Outstanding at December 31, 2009	13.0	$16.73	$90
Exercisable at December 31, 2009	10.0	$16.32	$69

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008, and 2007 was $2 million, $49 million, and $74 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2009.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$2.27 to $12.27	6.5	$ 8.24	5.1	4.5	$ 7.05	3.2
$12.28 to $22.27	3.8	$19.50	4.9	3.7	$19.50	4.9
$22.28 to $32.28	1.1	$28.04	6.5	0.8	$27.93	6.3
$32.29 to $42.29	1.6	$37.17	5.1	1.0	$37.61	3.1
Total	13.0	$16.73	5.2	10.0	$16.32	4.1

The estimated fair value at date of grant of options for our common stock granted in 2009, 2008, and 2007, using the Black-Scholes option pricing model, is as follows:

	2009	2008	2007
Weighted-average grant date fair value of options for our common stock granted during the year	$5.60	$12.83	$9.09
Weighted-average assumptions:			
Dividend yield	1.6%	1.2%	1.5%
Volatility	60.8%	33.4%	28.7%
Risk-free interest rate	2.3%	3.5%	4.6%
Expected life (years)	6.5	6.5	6.3

The expected dividend yield is based on the average annual dividend yield as of the grant date. Expected volatility is based on the historical volatility of our stock and the implied volatility of our stock based on traded options. In calculating historical volatility, returns during calendar year 2002 were excluded as the extreme volatility during that time is not reasonably expected to be repeated in the future. The risk-free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life of the option is based on historical exercise behavior and expected future experience.

Cash received from stock option exercises was $2 million, $32 million, and $56 million during 2009, 2008, and 2007, respectively; and the tax benefit realized was $1 million, $17 million, and $27 million, respectively.

Nonvested Restricted Stock Units

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit expense, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2009.

Restricted Stock Units	Shares	Weighted-Average Fair Value*
	(Millions)	
Nonvested at December 31, 2008	4.4	$22.91
Granted	3.4	$10.23
Forfeited	(0.1)	$20.65
Vested	(1.6)	$17.93
Nonvested at December 31, 2009	6.1	$16.24

* Performance-based shares are primarily valued using the end-of-period market price until certification that the performance objectives have been completed, a value of zero once it has been determined that it is unlikely that performance objectives will be met, or a valuation pricing model. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2009	2008	2007
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$10.23	$30.13	$30.79
Total fair value of restricted stock units vested during the year ($'s in millions)	$ 28	$ 48	$ 33

Performance-based shares granted under the Plan represent 29 percent of nonvested restricted stock units outstanding at December 31, 2009. These grants may be earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 14. Fair Value Measurements

Fair value is the amount received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

- Level 1 — Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange traded.

- Level 2 — Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 primarily consists of over-the-counter (OTC) instruments such as forwards, swaps, and options. These options, which hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Prior to the third quarter of 2009, these options were included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. However, due to the increased transparency, we now consider this input to be observable and have included these options in Level 2.

- Level 3 — Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements Using:

	December 31, 2009				December 31, 2008			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(Millions)				(Millions)		
Assets:								
Energy derivatives	$178	$911	$ 5	$1,094	$680	$1,223	$547	$2,450
Other assets	22	—	—	22	13	—	7	20
Total assets	$200	$911	$ 5	$1,116	$693	$1,223	$554	$2,470
Liabilities:								
Energy derivatives	$177	$826	$ 3	$1,006	$615	$1,313	$ 40	$1,968
Total liabilities	$177	$826	$ 3	$1,006	$615	$1,313	$ 40	$1,968

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Contracts for which fair value can be estimated from executed transactions or broker quotes corroborated by other market data are generally classified within Level 2. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Our derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent expiring in the next 36 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade in less active markets with lower availability of pricing information requiring valuation models using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2009, consist of natural gas liquids swaps for our Midstream segment as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production and Midstream segments.

The following tables present a reconciliation of changes in the fair value of net derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Year Ended December 31,			
	2009		2008	
	Net Derivatives	Other Assets	Net Derivatives	Other Assets
	(Millions)			
Beginning balance	$ 507	$ 7	$ (14)	$10
Realized and unrealized gains (losses):				
Included in *income from continuing operations*	476	—	88	(3)
Included in other comprehensive income (loss)	(331)	—	486	—
Purchases, issuances, and settlements	(477)	(7)	(51)	—
Transfers into Level 3	—	—	3	—
Transfers out of Level 3	(173)	—	(5)	—
Ending balance	$ 2	$—	$507	$ 7
Unrealized gains included in *income from continuing operations* relating to instruments still held at December 31	$ 2	$—	$ —	$—

Realized and unrealized gains (losses) included in *income from continuing operations* for the above periods are reported in *revenues* in our Consolidated Statement of Income. Reclassification of fair value into and out of Level 3 is made at the end of each quarter.

The following table presents, by level within the fair value of hierarchy, certain assets that have been measured at fair value on a nonrecurring basis, including certain items reported as discontinued operations.

Fair Value Measurements Using:

	December 31, 2009			Total Losses For The Year Ended December 31, 2009
	Level 1	Level 2	Level 3	
			(Millions)	
Impairments:				
Midstream Venezuelan property (see Note 2)	$—	$—	$(a)	$(211)
Midstream investment in Accroven (see Note 3)	—	—	(b)	(75)
Exploration & Production cost-based investment (see Note 3)	—	—	(b)	(11)
Exploration & Production unproved properties (see Note 4)	—	—	(c)	(15)
	$—	$—		$(312)

(a) Fair value measured at March 31, 2009, was $106 million. These assets were expropriated by the Venezuelan government during the second quarter of 2009 and the entities that previously owned these assets are no longer consolidated within our Midstream segment. We recorded our retained noncontrolling investment in these entities at zero and recognized a gain of $9 million on the deconsolidation. (See Note 2.)

(b) Fair value measured at March 31, 2009, was zero.

(c) Fair value measured at December 31, 2009, is $22 million.

Note 15. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the short-term maturity of these instruments. Current and noncurrent restricted cash is included in *other current assets and deferred charges* and *other assets and deferred charges*, respectively, in the Consolidated Balance Sheet.

ARO Trust Investments: Our Transcontinental Gas Pipe Line Company, LLC (Transco) subsidiary deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust specifically designated to fund future asset retirement obligations (ARO Trust). The ARO Trust invests in a portfolio of mutual funds that are reported at fair value in *other assets and deferred charges* in the Consolidated Balance Sheet and are classified as available-for-sale. However, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Long-term debt: The fair value of our publicly traded long-term debt is determined using indicative year-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings. At December 31, 2009 and 2008, approximately 97 percent of our long-term debt was publicly traded.

Guarantees: The *guarantees* represented in the following table consist primarily of guarantees we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on certain lease performance obligations. To estimate the fair value of the guarantees, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each guarantee based on the credit rating of WilTel's current owner and the term of the underlying obligation. The default rates are published by Moody's Investors Service. Guarantees, if recognized, are included in *accrued liabilities* in the Consolidated Balance Sheet.

Other: Includes notes and other noncurrent receivables, margin deposits, customer margin deposits payable, cost-based investments and auction rate securities.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 14 for discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	December 31,			
	2009		2008	
Asset (Liability)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Cash and cash equivalents	$ 1,867	$ 1,867	$ 1,438	$ 1,438
Restricted cash (current and noncurrent)	28	28	37	37
ARO Trust Investments	22	22	13	13
Long-term debt, including current portion(a)	(8,273)	(9,142)	(7,696)	(6,140)
Guarantees	(36)	(33)	(38)	(32)
Other	(23)	(25)(b)	4	(13)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	178	178	458	458
Other energy derivatives	(90)	(90)	24	24

(a) Excludes capital leases. (See Note 11.)

(b) Excludes certain cost-based investments in companies that are not publicly traded and therefore it is not practicable to estimate fair value. The carrying value of these investments was $2 million and $17 million at December 31, 2009 and December 31, 2008, respectively.

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We manage this risk on an enterprise basis and may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and NGLs attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

Exploration & Production produces, buys, and sells natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Exploration & Production's cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings.

Midstream produces and sells NGLs and olefins at different locations throughout the United States. Midstream also buys natural gas to satisfy the required fuel and shrink needed to generate NGLs and olefins. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas and NGL market prices, we may enter into NGL or natural gas swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas and NGLs. Midstream's cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Gas Marketing Services supports our natural gas business by providing marketing and risk management services, which include marketing the gas produced by Exploration & Production and procuring fuel and shrink for Midstream. Gas Marketing Services also enters into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements, and financial option contracts to mitigate the price risk associated with these contracts. Hedges for transportation contracts are designated as cash flow hedges and are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Hedges for storage contracts have not been designated as hedging instruments, despite economically hedging the expected cash flows generated by those agreements.

Other activities

Gas Marketing Services also enters into commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties. These legacy natural gas contracts include substantially offsetting positions and have an insignificant net impact on earnings.

Volumes

Our energy commodity derivatives are comprised of both contracts to purchase the commodity (long positions) and contracts to sell the commodity (short positions). Derivative transactions are categorized into four types:

- Fixed price: Includes physical and financial derivative transactions that settle at a fixed location price;
- Basis: Includes financial derivative transactions priced off the difference in value between a commodity at two specific delivery points;
- Index: Includes physical derivative transactions at an unknown future price;
- Options: Includes all fixed price options or combination of options (collars) that set a floor and/or ceiling for the transaction price of a commodity.

The following table depicts the notional amounts of the net long (short) positions in our commodity derivatives portfolio as of December 31, 2009. Natural gas is presented in millions of British Thermal Units (MMBtu), and NGLs is presented in gallons. The volumes presented for options that comprise zero-cost collars represent one side of the short position. While the index volumes are significant, they represent less than 1 percent of the fair value of our net derivative balance.

Derivative Notional Volumes		Measurement	Fixed Price	Basis	Index	Options
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(60,125,000)	(58,400,000)		(286,525,000)
Gas Marketing Services	Risk Management	MMBtu	—*	—*		
Midstream	Risk Management	MMBtu	1,247,500	412,500		
Midstream	Risk Management	Gallons	(30,240,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu			(56,204,466)	
Gas Marketing Services	Risk Management	MMBtu	(9,967,499)	(7,805,000)		
Midstream	Risk Management	MMBtu		835,000	64,418,920	
Midstream	Risk Management	Gallons			(2,998,800)	
Gas Marketing Services	Other	MMBtu	(851,850)	(3,737,500)		

* Volumes related to offsetting positions net to zero.

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	December 31, 2009	
	Assets	Liabilities
	(Millions)	
Designated as hedging instruments	$ 352	$ 174
Not designated as hedging instruments:		
Legacy natural gas contracts from former power business	505	526
All other	237	306
Total derivatives not designated as hedging instruments	742	832
Total derivatives	$1,094	$1,006

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in accumulated other comprehensive income (AOCI) or revenues.

	Year Ended December 31, 2009	Classification
	(Millions)	
Net gain recognized in other comprehensive income (effective portion)	$262	AOCI
Net gain reclassified from *accumulated other comprehensive loss* into income (effective portion)	$618	Revenues
Gain recognized in income (ineffective portion)	$ 4	Revenues

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Year Ended December 31, 2009
	(Millions)
Revenues	$37
Costs and operating expenses	33
Net gain	$ 4

The cash flow impact of our derivative activities is presented in the Consolidated Statement of Cash Flows as *changes in current and noncurrent derivative assets and liabilities.*

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor's and/or Moody's Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, Exploration & Production has an unsecured credit agreement with certain banks related to hedging activities. We are not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of Exploration & Production's domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money position on hedges entered into under the credit agreement.

As of December 31, 2009, we have collateral totaling $96 million posted to derivative counterparties, all of which is in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $167 million, which includes a reduction of $3 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, is $74 million.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in other comprehensive income and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of December 31, 2009, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to three years. Based on recorded values at December 31, 2009, $64 million of net gains (net of income tax provision of $39 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of December 31, 2009. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Guarantees

In addition to the guarantees and payment obligations discussed in Note 16, we have issued guarantees and other similar arrangements as discussed below.

We are required by our revolving credit agreement to indemnify lenders for any taxes required to be withheld from payments due to the lenders and for any tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $40 million at December 31, 2009, and $42 million at December 31, 2008. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees included in *accrued liabilities* on the Consolidated Balance Sheet is $36 million at December 31, 2009 and $38 million at December 31, 2008.

At December 31, 2009, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have a material adverse effect on our results of operations.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts and notes receivable

The following table summarizes concentration of receivables including those related to discontinued operations (see Note 2), net of allowances, by product or service:

	December 31, 2009	December 31, 2008
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services(1)	$599	$653
Transportation of natural gas and related products	173	158
Joint interest	56	86
Other	2	49
Total	$830	$946

(1) Includes $57 million net receivable from PDVSA at December 31, 2008. This amount has been fully reserved and subsequently deconsolidated in 2009. (See Note 2.)

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains, Gulf Coast, and Canada. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2009 and 2008, we did not incur any significant losses due to counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of December 31, 2009, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 35	$ 424
Energy marketers and traders	1	9
Financial institutions	661	661
	$697	1,094
Credit reserves		—
Gross credit exposure from derivatives		$1,094

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of December 31, 2009, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 17	$ 17
Energy marketers and traders	1	8
Financial institutions	230	230
	$248	255
Credit reserves		—
Net credit exposure from derivatives		$255

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade.

Our eight largest net counterparty positions represent approximately 95 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are five counterparty positions, representing 64 percent of our net credit exposure from derivatives, associated with Exploration & Production's hedging facility. (See Note 11.) Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

At December 31, 2009, the designated collateral agent holds $27 million of collateral support on our behalf under Exploration & Production's hedging facility. In addition, we hold collateral support, including letters of credit, of $25 million related to our other derivative positions.

Revenues

In 2009, 2008, and 2007, there were no customers for which our sales exceeded 10 percent of our consolidated revenues.

Note 16. Contingent Liabilities and Commitments

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the U.S. Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a June 2008 U.S. Supreme Court decision, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds depending on the results of further proceedings at the FERC. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. While we are not a party to the cases involved in the U.S. Supreme Court decision, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to the FERC's reconsideration of the contract terms at issue in the decision. The FERC has directed the parties to provide additional information on certain issues remanded by the U.S. Supreme Court, but delayed the submission of this information to permit the parties to explore possible settlements of the contractual disputes. The parties to the remanded proceeding have engaged the FERC's Dispute Resolution Service to assist with settlement discussions.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as the counterparty to the contracts described above and various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that will be used towards satisfying any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling $24 million at December 31, 2009. Collection of the interest and the payment of interest on refund amounts from the escrow accounts are subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings.

Challenges to virtually every aspect of the refund proceedings, including the refund period, continue to be made. Despite two FERC decisions that will affect the refund calculation, significant aspects of the refund calculation process remain unsettled, and the final refund calculation has not been made. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us.

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states.

- The federal court in Nevada currently presides over cases that were transferred to it from state courts in Colorado, Kansas, Missouri, and Wisconsin. In 2008, the federal court in Nevada granted summary judgment in the Colorado case in favor of us and most of the other defendants, and on January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal. We expect that the Colorado plaintiffs will appeal, but the appeal cannot occur until the case against the remaining defendant is concluded.
- On October 29, 2008, the Tennessee appellate court reversed the state court's dismissal of the plaintiffs' claims on federal preemption grounds and sent the case back to the lower court for further proceedings. We and other defendants appealed the reversal to the Tennessee Supreme Court, and we expect the court's ruling in 2010.
- On December 8, 2009, the Missouri appellate court upheld the trial court's dismissal of a case for lack of standing. The plaintiff has appealed to the Missouri Supreme Court.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2009, we had accrued liabilities of $5 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco's rates.

Beginning in the mid-1980s, our Northwest Pipeline GP (Northwest Pipeline) subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional assessments and remediation activities at certain sites to comply with Washington's current environmental standards. At December 31, 2009, we have accrued liabilities of $8 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline's rates.

In March 2008, the EPA issued new air quality standards for ground level ozone. In September 2009, the EPA announced that it would reconsider those standards. In January 2010, the EPA proposed more stringent standards, which are expected to be final in August 2010. The EPA expects that new eight-hour ozone nonattainment areas will be designated in July 2011. The new standards and nonattainment areas will likely impact the operations of our interstate gas pipelines and cause us to incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet these regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2009, we have accrued liabilities totaling $8 million for these costs.

In April 2007, the New Mexico Environment Department's (NMED) Air Quality Bureau issued a notice of violation (NOV) to Williams Four Corners LLC (Four Corners) that alleged various emission and reporting violations in connection with our Lybrook gas processing plant's flare and leak detection and repair program. In December 2007, the NMED proposed a penalty of approximately $3 million. In July 2008, the NMED issued an NOV to Four Corners that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties with the NMED.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA's investigation of our compliance with the Clean Air Act. On March 28, 2008, the EPA issued NOVs alleging violations of Clean Air Act requirements at these compressor stations. We met with the EPA in May 2008 and submitted our response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, we submitted the requested information.

In January 2010, the Colorado Department of Public Health and Environment (CDPHE) proposed a penalty of $113,750 against Williams Production RMT Company for alleged permit violations at four compressor stations in Colorado. We are discussing the proposed penalties with CDPHE.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities include those described below.

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At December 31, 2009, we have accrued liabilities of $8 million for such excess costs.

Other

At December 31, 2009, we have accrued environmental liabilities of $13 million related primarily to our:

- Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- Discontinued petroleum refining facilities;
- Former exploration and production and mining operations.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but the amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants opposed class certification and on September 18, 2009, the court denied plaintiffs' most recent motion to certify the class. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay (a joint venture between Gulsby and Bay Ltd.) for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we recorded a charge based on our estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $20 million. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs' claims for attorneys' fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. Gulf Liquids, Gulsby, Gulsby-Bay, Bay Ltd., and NAICO appealed the judgment. In February 2009, we settled with certain of these parties and reduced our liability as of December 31, 2008, by $43 million, including $11 million of interest. If the judgment is upheld on appeal, our remaining liability will be substantially less than the amount of our accrual for these matters.

Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary, Williams Production RMT Company, additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. The negative assessment for the 2000-2002 time period resulted in additional severance and ad valorem taxes of $4 million. We disputed the DOA's interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. We appealed to the Wyoming Supreme Court but the court ruled against us in December 2008. On April 14, 2009, the Wyoming Supreme Court denied our petition for rehearing and issued its mandate affirming its prior published decision in this case. We had accrued liabilities of $39 million as of December 31, 2008, related to this matter representing our estimated exposure, including interest, through the end of 2008. During 2009, we reduced our accrual for our estimated exposure by $6 million, including interest, and made net payments of $29 million. While certain issues involved remain to be resolved, we do not expect any material future changes from this matter and estimate our remaining net exposure, including interest, to be approximately $4 million at December 31, 2009, all of which has been recorded.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. We have reached a final partial settlement agreement for an amount that was previously accrued. We anticipate trial in 2010 on remaining issues related to royalty payment calculation and obligations under specific lease provisions. While we are not able to estimate the amount of any additional exposure at this time, it is reasonably possible that plaintiff's claims could reach a material amount.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5, 2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At December 31, 2009, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a material adverse effect upon our future liquidity or financial position.

Commitments

Commitments for construction and acquisition of property, plant and equipment are approximately $221 million at December 31, 2009.

As part of managing our commodity price risk, we utilize contracted pipeline capacity primarily to move our natural gas production to other locations with more favorable pricing differentials. Our commitments under these contracts are as follows:

	(Millions)
2010	$ 166
2011	170
2012	159
2013	141
2014	122
Thereafter	526
Total	$1,284

We also have certain commitments to an equity investee for natural gas gathering and treating services which total $188 million over approximately eight years.

Note 17. Accumulated Other Comprehensive Loss

The table below presents changes in the components of *accumulated other comprehensive loss.*

	Income (Loss)						
			Pension Benefits		Other Postretirement Benefits		
	Cash Flow Hedges	Foreign Currency Translation	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain (Loss)	Total
	(Millions)						
Balance at December 31, 2006	$ 20	$ 76	$ (4)	$(150)	$ (4)	$ 2	$ (60)
2007 Change:							
Pre-income tax amount	201	53	—	68	—	15	337
Income tax provision	(77)	—	—	(26)	—	(6)	(109)
Net reclassification into earnings of derivative instrument gains (net of a $187 million income tax provision)	(303)*	—	—	—	—	—	(303)
Amortization included in net periodic benefit expense	—	—	—	19	2	—	21
Income tax provision on amortization	—	—	—	(8)	(1)	—	(9)
	(179)	53	—	53	1	9	(63)
Allocation of other comprehensive loss to noncontrolling interests	2	—	—	—	—	—	2
Balance at December 31, 2007	(157)	129	(4)	(97)	(3)	11	(121)
2008 Change:							
Pre-income tax amount	714	(76)	—	(565)	16	(15)	74
Income tax (provision) benefit	(270)	—	—	213	(8)	6	(59)
Net reclassification into earnings of derivative instrument losses (net of a $7 million income tax benefit)	11	—	—	—	—	—	11
Amortization included in net periodic benefit expense	—	—	1	13	1	—	15
Income tax provision on amortization	—	—	—	(5)	—	—	(5)
	455	(76)	1	(344)	9	(9)	36
Allocation of other comprehensive income (loss) to noncontrolling interests	(2)	—	—	7	—	—	5
Balance at December 31, 2008	296	53	(3)	(434)	6	2	(80)
2009 Change:							
Pre-income tax amount	262	83	—	44	7	(1)	395
Income tax (provision) benefit	(99)	—	—	(17)	—	1	(115)
Net reclassification into earnings of derivative instrument gains (net of a $234 million income tax provision)	(384)	—	—	—	—	—	(384)
Amortization included in net periodic benefit expense	—	—	1	42	(4)	—	39
Income tax (provision) benefit on amortization	—	—	(1)	(16)	1	—	(16)
	(221)	83	—	53	4	—	(81)
Allocation of other comprehensive income to noncontrolling interests	—	—	—	(7)	—	—	(7)
Balance at December 31, 2009	$ 75	$136	$ (3)	$(388)	$10	$ 2	$(168)

* Includes a $429 million reclassification into earnings of deferred net hedge gains related to the sale of our power business. (See Note 2.)

Note 18. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P., are consolidated within our Midstream and Gas Pipeline segments, respectively. (See Note 1.) Other primarily consists of corporate operations.

In February 2010, we completed our strategic restructuring that will change our reportable segments in first-quarter 2010. (See Note 19 of Notes to Consolidated Financial Statements.)

Performance Measurement

We currently evaluate performance based on *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses, equity earnings (losses)* and *income (loss) from investments*. The accounting policies of the segments are the same as those described in Note 1. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

The primary types of costs and operating expenses by segment can be generally summarized as follows:

- Exploration & Production — depletion, depreciation and amortization, lease and facility operating expenses and operating taxes;
- Gas Pipeline — depreciation and operation and maintenance expenses;
- Midstream Gas & Liquids — commodity purchases (primarily for NGL, crude and olefin marketing, shrink, feedstock and fuel), depreciation, and operation and maintenance expenses;
- Gas Marketing Services — commodity purchases primarily in support of commodity marketing and risk management activities.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Gas Marketing segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing bears the counterparty performance risks associated with the unrelated third parties in these transactions. Additionally, Exploration & Production may enter into transactions directly with third parties under their credit agreement. (See Note 11.) Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

External revenues of our Exploration & Production segment are presented net of transportation expenses and royalties due third parties on intersegment sales. In some periods, transportation expenses and royalties due third parties on intersegment sales may exceed other external revenues.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	United States	Other	Total
		(Millions)	
Revenues from external customers:			
2009	$ 8,065	$190	$ 8,255
2008	11,629	261	11,890
2007	9,966	273	10,239
Long-lived assets:			
2009	$19,247	$410	$19,657
2008	18,419	335	18,754
2007	16,279	361	16,640

Our foreign operations are primarily located in Canada and South America. *Long-lived assets* are comprised of property, plant and equipment, goodwill and other intangible assets.

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income and *other financial information* related to *long-lived assets.*

	Exploration & Production	Gas Pipeline	Midstream	Gas Marketing	Other	Eliminations	Total
			(Millions)				
2009							
Segment revenues:							
External	$ 564	$1,563	$3,516	$2,599	$13	$ —	$ 8,255
Internal	1,655	28	72	453	14	(2,222)	—
Total revenues	$2,219	$1,591	$3,588	$3,052	$27	$(2,222)	$ 8,255
Segment profit (loss)	$ 418	$ 667	$ 640	$ (18)	$(1)	$ —	$ 1,706
Less:							
Equity earnings	18	66	52	—	—	—	136
Loss from investments	—	—	(75)	—	—	—	(75)
Segment operating income (loss)	$ 400	$ 601	$ 663	$ (18)	$(1)	$ —	1,645
General corporate expenses							(164)
Total operating income							$ 1,481
Other financial information:							
Additions to long-lived assets	$1,324	$ 518	$ 528	$ —	$27	$ —	$ 2,397
Depreciation, depletion & amortization	$ 889	$ 334	$ 217	$ 1	$20	$ —	$ 1,461
2008							
Segment revenues:							
External	$ (215)	$1,600	$5,124	$5,371	$10	$ —	$11,890
Internal	3,336	34	56	1,041	14	(4,481)	—
Total revenues	$3,121	$1,634	$5,180	$6,412	$24	$(4,481)	$11,890
Segment profit (loss)	$1,260	$ 689	$ 871	$ 3	$(3)	$ —	$ 2,820
Less:							
Equity earnings	20	59	58	—	—	—	137
Income from investments	—	—	1	—	—	—	1
Segment operating income (loss)	$1,240	$ 630	$ 812	$ 3	$(3)	$ —	2,682
General corporate expenses							(149)
Total operating income							$ 2,533
Other financial information:							
Additions to long-lived assets	$2,563	$ 413	$ 676	$ —	$42	$ —	$ 3,694
Depreciation, depletion & amortization	$ 737	$ 321	$ 203	$ 1	$18	$ —	$ 1,280
2007							
Segment revenues:							
External	$ (167)	$1,576	$4,895	$3,924	$11	$ —	$10,239
Internal	2,188	34	38	709	15	(2,984)	—
Total revenues	$2,021	$1,610	$4,933	$4,633	$26	$(2,984)	$10,239
Segment profit (loss)	$ 756	$ 673	$ 994	$ (337)	$(1)	$ —	$ 2,085
Less equity earnings	25	51	61	—	—	—	137
Segment operating income (loss)	$ 731	$ 622	$ 933	$ (337)	$(1)	$ —	1,948
General corporate expenses							(161)
Total operating income							$ 1,787
Other financial information:							
Additions to long-lived assets	$1,717	$ 546	$ 609	$ —	$27	$ —	$ 2,899
Depreciation, depletion & amortization	$ 535	$ 315	$ 184	$ 7	$10	$ —	$ 1,051

The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2009	December 31, 2008	December 31, 2007	December 31, 2009	December 31, 2008	December 31, 2007
			(Millions)			
Exploration & Production(1)	$ 9,682	$10,286	$ 8,692	$ 95	$ 87	$ 72
Gas Pipeline	9,421	9,149	8,624	429	570	483
Midstream Gas & Liquids	7,245	6,501	6,066	360	290	321
Gas Marketing Services(2)	1,324	3,064	4,437	—	—	—
Other	3,535	3,532	3,592	—	—	—
Eliminations	(5,928)	(7,055)	(7,073)	—	—	—
	25,279	25,477	24,338	884	947	876
Discontinued operations (see Note 2)	1	529	723	—	—	—
Total	$25,280	$26,006	$25,061	$884	$947	$876

(1) The 2008 increase in Exploration & Production's total assets is due to an increase in property, plant and equipment — net as a result of increased drilling activity.

(2) The decrease in Gas Marketing Services' total assets for 2009 and 2008 is primarily due to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services' derivative assets are substantially offset by their derivative liabilities.

Note 19. Subsequent Events

Strategic Restructuring

On February 17, 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to WPZ in exchange for cash and WPZ common units. The contributed businesses are currently reported within our Gas Pipeline and Midstream segments. The aggregate consideration received from WPZ consisted of the following:

- The issuance to us of 203 million WPZ Class C units, which are identical to common units, except for a prorated initial distribution;
- An increase in our general-partner's capital account to maintain our 2 percent general-partner interest and the issuance of WPZ general-partner units equal to 2/98th of the number of WPZ common units issued;
- Proceeds from the sale of $3.5 billion aggregate principal amount of senior unsecured notes of WPZ to qualified institutional buyers, net of all expenses incurred by WPZ in connection with these transactions.

Utilizing the cash consideration received from WPZ, we retired $3 billion of debt and paid $574 million in related premiums as well as other transaction costs.

Long-term Debt and Credit Facilities

The WPZ $3.5 billion senior unsecured notes issued, at face, include:

	(Millions)
3.80% Senior Notes due 2015	$ 750
5.25% Senior Notes due 2020	1,500
6.30% Senior Notes due 2040	1,250
Total	$3,500

In connection with the issuance of the $3.5 billion unsecured notes previously discussed, WPZ entered into registration rights agreements with the initial purchasers of the notes. WPZ is obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offers within 30 business days after such effective date. WPZ may also be required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If WPZ fails to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of default, increasing by an additional 0.25 percent per annum with respect to each subsequent 90-day period thereafter, up to a maximum amount for all such defaults of 0.5 percent annually. Following the cure of any registration defaults the accrual of additional interest will cease.

The $3 billion of aggregate principal corporate debt retired includes:

	(Millions)
7.125% Notes due 2011	$ 429
8.125% Notes due 2012	602
7.625% Notes due 2019	668
8.75% Senior Notes due 2020	586
7.875% Notes due 2021	179
7.70% Debentures due 2027	98
7.50% Debentures due 2031	163
7.75% Notes due 2031	111
8.75% Notes due 2032	164
Total	$3,000

As part of the restructuring, WPZ, Transco and Northwest Pipeline, as co-borrowers, entered into a new $1.75 billion three-year senior unsecured revolving credit facility. The full amount of the new credit facility is available to WPZ to the extent not otherwise utilized by Transco and Northwest Pipeline, and may be increased by up to an additional $250 million. Transco and Northwest Pipeline each have access to borrow up to $400 million under the new facility to the extent not otherwise utilized. WPZ utilized $250 million of the new credit facility to repay a term loan that was outstanding under its previously existing $450 million facility. As WPZ will be funding Midstream and Gas Pipeline projects, we reduced our $1.5 billion unsecured credit facility that expires May 2012 to $900 million and removed Transco and Northwest Pipeline as borrowers. Our unsecured credit facility that expires December 2013 and is used to facilitate our natural gas production hedging remains unchanged.

The new credit facility contains various covenants that limit, among other things, a borrower's and its respective subsidiaries' ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, and allow any material change in the nature of its business.

Under the new credit facility, WPZ is required to maintain a ratio of debt to EBITDA (each as defined) of no greater than 5.00 to 1.00 for itself and its consolidated subsidiaries. For Transco and Northwest Pipeline and their consolidated subsidiaries, the ratio of debt to capitalization (each as defined) is not permitted to be greater than 55 percent. Each of the above ratios will be tested quarterly, beginning with the second quarter of 2010, and the debt to EBITDA ratio will be measured on a rolling four-quarter basis.

Contributed Businesses

The contributed Gas Pipeline businesses include 100 percent of Transco, 65 percent of Northwest Pipeline, and 24.5 percent of Gulfstream. We also contributed our general- and limited-partner interests in WMZ, which owns the remaining 35 percent of Northwest Pipeline. The contributed Midstream businesses include significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, a recently acquired business in Pennsylvania's Marcellus Shale region, and various equity investments in domestic processing and fractionation assets. Our remaining 25.5 percent ownership interest in Gulfstream and our Canadian, Venezuelan, and olefins operations are excluded from the transaction. Additionally, our Exploration & Production business was not included in this transaction.

Segment Changes

As a result of the restructuring, we will change our segment reporting structure to align with the new parent-level focus, resource allocation management and related governance provisions. Beginning with reporting first-quarter 2010 results, our reportable segments will be Williams Partners, Exploration & Production, and Other.

Exploration & Production will include the current Gas Marketing Services segment, and Other will include the Canadian and olefins operations and the 25.5 percent interest in Gulfstream, as well as corporate operations.

Stockholders' Equity & Noncontrolling Interests

We will account for the change in our ownership interest in WPZ as an equity transaction and adjust the carrying amount of noncontrolling interest to reflect this change in ownership. As a result, we expect our *capital in excess of par value* will decrease with a corresponding increase to *noncontrolling interests in consolidated subsidiaries*.

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows (millions, except per-share amounts).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2009				
Revenues	$1,922	$1,909	$2,098	$2,326
Costs and operating expenses	1,444	1,392	1,537	1,708
Income from continuing operations	19	151	192	222
Net income (loss)	(224)	169	194	222
Amounts attributable to The Williams Companies, Inc.:				
Income from continuing operations	2	123	141	172
Net income (loss)	(172)	142	143	172
Basic earnings per common share:				
Income from continuing operations	—	.21	.24	.30
Diluted earnings per common share:				
Income from continuing operations	—	.21	.24	.29
2008				
Revenues	$3,095	$3,574	$3,137	$2,084
Costs and operating expenses	2,264	2,614	2,280	1,618
Income from continuing operations	448	471	411	137
Net income	539	500	421	132
Amounts attributable to The Williams Companies, Inc.:				
Income from continuing operations	411	412	360	123
Net income	500	437	366	115
Basic earnings per common share:				
Income from continuing operations	.70	.71	.62	.21
Diluted earnings per common share:				
Income from continuing operations	.69	.69	.61	.21

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

Amounts reported above for 2008 have been adjusted to reflect the presentation of certain revenues and costs for Midstream on a net basis. These adjustments reduced previously reported *revenues* and *costs and operating expenses* by the same amount, with no impact on segment profit. The reductions were as follows (in millions):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008	$69	$83	$64	$79

Net income for fourth-quarter 2009 includes the following pre-tax items:

- $40 million gain related to the sale of our Cameron Meadows processing plant at Midstream (see Note 4 of Notes to Consolidated Financial Statements);
- $17 million unfavorable depletion adjustment at Exploration & Production primarily as the result of new oil and gas accounting guidance that requires we value our reserves using an average price;
- $15 million impairment of certain natural gas properties at Exploration & Production (see Note 4).

Net income for second-quarter 2009 includes the following pre-tax items:

- $15 million gain related to our former coal operations (see summarized results of discontinued operations at Note 2);
- $11 million of income related to the recovery of certain royalty overpayments from prior periods (see Note 4).

Net income for first-quarter 2009 includes the following pre-tax items:

- $211 million impairment of Venezuela property, plant and equipment (see summarized results of discontinued operations at Note 2);
- $75 million impairment of a Venezuelan investment in Accroven at Midstream (see Note 3);
- $48 million of bad debt expense related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2);
- $30 million net charge related to the write-off of certain deferred charges related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2);
- $34 million of penalties from early release of drilling rigs at Exploration & Production (see Note 4);
- $11 million impairment of a Venezuelan cost-based investment at Exploration & Production (see Note 3).

Net income for first-quarter 2009 also includes a $76 million benefit from the reversal of deferred tax balances related to our discontinued Venezuela operations (see summarized results of discontinued operations at Note 2).

Net income for fourth-quarter 2008 includes both the unfavorable impact of the significant decline in energy commodity prices and the following pre-tax items:

- $129 million impairment of certain natural gas producing properties at Exploration & Production (see Note 4);
- $43 million of income including associated interest related to the partial settlement of the Gulf Liquids litigation at Midstream (see Note 16);
- $38 million accrual for Wyoming severance taxes and associated interest expense at Exploration & Production (see Notes 4 and 16);
- $12 million gain related to the favorable resolution of a matter involving pipeline transportation rates associated with our former Alaska operations (see summarized results of discontinued operations at Note 2).

Net income for fourth-quarter 2008 also includes a $46 million adjustment to decrease state income taxes (net of federal benefit) due to a reduction in our estimate of the effective deferred state rate (see Note 5).

Net income for third-quarter 2008 includes the following pre-tax items:

- $14 million impairment of certain natural gas producing properties at Exploration & Production (see Note 4);
- $10 million gain from the sale of certain south Texas assets at Gas Pipeline (see Note 4).

Net income for second-quarter 2008 includes the following pre-tax items:

- $54 million gain related to the favorable resolution of a matter involving pipeline transportation rates associated with our former Alaska operations (see summarized results of discontinued operations at Note 2);
- $30 million gain recognized upon receipt of the remaining proceeds related to the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production (see Note 4);

- $10 million charge associated with a settlement primarily related to the sale of natural gas liquids pipeline systems in 2002 (see summarized results of discontinued operations at Note 2);
- $10 million charge associated with an oil purchase contract related to our former Alaska refinery (see summarized results of discontinued operations at Note 2).

Net income for first-quarter 2008 includes the following pre-tax items:

- $118 million gain on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production (see Note 4);
- $74 million gain related to the favorable resolution of a matter involving pipeline transportation rates associated with our former Alaska operations (see summarized results of discontinued operations at Note 2);
- $54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank (see summarized results of discontinued operations at Note 2).

THE WILLIAMS COMPANIES, INC.
SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

We have significant oil and gas producing activities primarily in the Rocky Mountain and Mid-continent areas of the United States. Additionally, we have international oil- and gas-producing activities, primarily in Argentina. Proved reserves and revenues related to international activities are approximately 4 percent and 3 percent, respectively, of our total international and domestic proved reserves and revenues. Accordingly, the following information relates only to the oil and gas activities in the United States.

Capitalized Costs

	As of December 31,	
	2009	2008
	(Millions)	
Proved properties	$ 9,165	$ 8,099
Unproved properties	953	806
	10,118	8,905
Accumulated depreciation, depletion and amortization and valuation provisions	(3,212)	(2,353)
Net capitalized costs	$ 6,906	$ 6,552

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $762 million and $726 million, net, for 2009 and 2008, respectively. The capitalized cost amounts do not include approximately $1 billion of goodwill related to the purchase of Barrett Resources Corporation (Barrett) in 2001.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs, and successful exploratory wells.
- Unproved properties consist primarily of costs for acquired unproven reserves.

Costs Incurred

	For The Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Acquisition	$ 305	$ 543	$ 82
Exploration	51	38	38
Development	878	1,699	1,374
	$1,234	$2,280	$1,494

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: The 2009 costs are primarily for additional leasehold and reserve acquisitions in the Piceance basin, and includes $85 million of proved property values. The 2008 and 2007 costs are primarily for additional leasehold and reserve acquisitions in the Piceance and Fort Worth basins. Included in the 2008 acquisition amounts is $140 million of proved property values and $71 million related to an interest in a portion of acquired assets that a third party subsequently exercised its contractual option to purchase from us, on the same terms and conditions.
- Exploration costs include the costs of geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions, and the cost of retaining undeveloped leaseholds.

- Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip wells in our development basins.

Results of Operations

	For The Year Ended December 31,		
	2009	2008	2007
		(Millions)	
Revenues:			
Oil and gas revenues	$1,974	$2,699	$1,788
Other revenues	170	350	169
Total revenues	2,144	3,049	1,957
Costs:			
Production costs	487	610	423
General & administrative	162	169	144
Exploration expenses	58	27	21
Depreciation, depletion & amortization	873	724	523
Impairment of certain natural gas properties in the Arkoma basin	—	143	—
Other expenses	178	295	134
Total costs	1,758	1,968	1,245
Results of operations	386	1,081	712
Provision for income taxes	(146)	(406)	(273)
Exploration and production net income	$ 240	$ 675	$ 439

- Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit. Amounts for 2008 exclude a $148 million gain on sale of a contractual right to a production payment on certain future international hydrocarbon production.
- Oil and gas revenues consist primarily of natural gas production sold to the Gas Marketing Services subsidiary and includes the impact of hedges, including intercompany hedges.
- Other revenues and other expenses consist of activities within the Exploration & Production segment that are not a direct part of the producing activities. These nonproducing activities include acquisition and disposition of other working interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to the Gas Marketing Services subsidiary or third-party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain nonoperating benefits to a third party. Other expenses also include $15 million write-down of costs associated with acquired unproved reserves.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include production taxes other than income taxes and administrative expenses in support of production activity. Excluded are depreciation, depletion and amortization of capitalized costs.
- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes, and the cost of retaining undeveloped leaseholds including lease amortization and impairments.
- Depreciation, depletion and amortization includes depreciation of support equipment. Additionally, 2009 includes $17 million additional depreciation, depletion and amortization as a result of our recalculation of fourth quarter depreciation, depletion and amortization utilizing our year-end reserves which were lower than 2008. The lower reserves are primarily a result of the application of new rules issued by the SEC.

Proved Reserves

	2009	2008	2007
		(Bcfe)	
Proved reserves at beginning of period	4,339	4,143	3,701
Revisions	(859)	(220)	(106)
Purchases	159	31	19
Extensions and discoveries	1,051	791	863
Wellhead production	(435)	(406)	(334)
Proved reserves at end of period	4,255	4,339	4,143
Proved developed reserves at end of period	2,387	2,456	2,252

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as 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 a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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. Proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

- A significant portion of the revisions for 2009 are a result of the impact of the new SEC rules. Proved reserves are lower because of the lower 12 month average, first-of-the-month price as compared to the 2008 year-end price and the revision of proved undeveloped reserve estimates based on new guidance. Approximately one-half of the revisions for 2008 relate to the impact of lower average year-end natural gas prices used in 2008 compared to the 2007.

- Extensions and discoveries in 2009 are higher this year as compared to prior years due in part to the expanded definition of oil and gas reserves supported by reliable technology and reasonable certainty used for reserves estimation.

- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Crude oil reserves are insignificant and have been included in the proved reserves on a basis of billion cubic feet equivalents (Bcfe).

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves. During 2009 we adopted prescribed accounting revisions associated with oil and gas authoritative guidance. Those revisions include using the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. These revisions are reflected in our 2009 amounts. For the year-ended December 31, 2009, the average natural gas equivalent price used in the estimates was $2.76 per MMcfe. For the years ended December 31, 2008 and 2007, the average year-end natural gas equivalent prices used in the estimates were $4.41 and $5.78 per MMcfe, respectively. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs. Of the $2,833 million of future development costs, approximately 60 percent is estimated to be spent in 2010, 2011 and 2012.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

	At December 31, 2009	At December 31, 2008
	(Millions)	
Future cash inflows	$11,729	$19,127
Less:		
Future production costs	3,990	5,516
Future development costs	2,833	3,772
Future income tax provisions	1,404	3,284
Future net cash flows	3,502	6,555
Less 10 percent annual discount for estimated timing of cash flows	(1,789)	(3,382)
Standardized measure of discounted future net cash flows	$ 1,713	$ 3,173

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	2009	2008	2007
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 3,173	$ 4,803	$ 2,856
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,006)	(2,091)	(1,426)
Net change in prices and production costs	(3,310)	(2,548)	2,019
Extensions, discoveries and improved recovery, less estimated future costs	1,131	1,423	2,163
Development costs incurred during year	389	817	738
Changes in estimated future development costs	701	(724)	(931)
Purchase of reserves in place, less estimated future costs	171	55	48
Revisions of previous quantity estimates	(923)	(395)	(266)
Accretion of discount	450	714	434
Net change in income taxes	932	1,108	(1,108)
Other	5	11	276
Net changes	(1,460)	(1,630)	1,947
Standardized measure of discounted future net cash flows end of period	$ 1,713	$ 3,173	$ 4,803

In relation to the new SEC rules, we estimate that the standardized measure of discounted future net cash flows declined approximately $840 million on a before tax basis and excluding the overall price rule impact. The significant components of this decline include an estimated $640 million decrease included in revisions of previous quantity estimates and a related $430 million decrease included in the net change in prices and production costs, partially offset by a $210 million increase included in extensions, discoveries and improved recovery, less estimated future costs. Additionally, we estimate that a significant portion of the remaining net change in price and production costs is due to the application of the new pricing rules which resulted in the use of lower prices at December 31, 2009 than would have resulted under the previous rules.

THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS: Charged (Credited) To Cost and Expenses	ADDITIONS: Other	Deductions	Ending Balance
			(Millions)		
Year ended December 31, 2009:					
Allowance for doubtful accounts — accounts and notes receivable(a)	$ 29	$ 4	$—	$11(d)	$ 22
Deferred tax asset valuation allowance(a)	3	1	—	—	4
Price-risk management credit reserves — assets(a)	6	(3)(e)	(3)(f)	—	—
Price-risk management credit reserves — liabilities(b)	(15)	12(e)	—	—	(3)
Year ended December 31, 2008:					
Allowance for doubtful accounts — accounts and notes receivable(a)	16	15	—	2(d)	29
Deferred tax asset valuation allowance(a)	50	(14)	—	33(d)	3
Price-risk management credit reserves — assets(a)	1	1(e)	4(f)	—	6
Price-risk management credit reserves — liabilities(b)	—	(16)(e)	1(f)	—	(15)
Year ended December 31, 2007:					
Allowance for doubtful accounts — accounts and notes receivable(a)	13	3	—	—	16
Deferred tax asset valuation allowance(a)	36	14	—	—	50
Price-risk management credit reserves — assets(a)	7	(6)(e)	—	—	1
Processing plant major maintenance accrual	8	—	—	8(c)	—

(a) Deducted from related assets.

(b) Deducted from related liabilities.

(c) Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities*. As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method of accounting for these costs going forward.

(d) Represents balances written off, reclassifications, and recoveries.

(e) Included in *revenues*.

(f) Included in *accumulated other comprehensive loss*.

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

None.

Item 9A. *Controls and Procedures*

Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

See report set forth above in Item 8, "Financial Statements and Supplementary Data."

Changes in Internal Controls Over Financial Reporting

There have been no changes during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Item 9B. *Other Information*

None.

PART III

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

The information regarding our directors and nominees for director required by Item 401 of Regulation S-K will be presented under the heading. "Proposal 1 — Election of Directors" in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 20, 2010 (Proxy Statement), which information is incorporated by reference herein.

Information regarding our executive officers required by Item 401(b) of Regulation S-K is presented at the end of Part I herein and captioned "Executive Officers of the Registrant" as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K.

Information required by Item 405 of Regulation S-K will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement, which information is incorporated by reference herein.

Information required by paragraphs (c)(3), (d)(4) and (d)(5) of Item 407 of Regulation S-K will be included under the heading "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

We have adopted a Code of Ethics for Senior Officers that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics for Senior Officers, together with our Corporate Governance Guidelines, the charters for each of our board committees, and our Code of Business Conduct applicable to all employees are available on our Internet website at *http://www.williams.com.* We will provide, free of charge, a copy of our Code of Ethics or any of our other corporate documents listed above upon written request to our Corporate Secretary at Williams, One Williams Center, Suite 4700, Tulsa, Oklahoma 74172. We intend to disclose any amendments to or waivers of the Code of Ethics on behalf of our Chief Executive Officer, Chief Financial Officer, Controller, and persons performing similar functions on our Internet website at *http://www.williams.com* under the Investor Relations caption, promptly following the date of any such amendment or waiver.

Item 11. *Executive Compensation*

The information required by Item 402 and paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K regarding executive compensation will be presented under the headings "Compensation Discussion and Analysis," "Executive Compensation and Other Information," and "Compensation Committee Report on Executive Compensation" in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading "Compensation Committee Report on Executive Compensation" in our Proxy Statement is furnished and shall not be deemed to be filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

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

The information regarding securities authorized for issuance under equity compensation plans required by Item 201(d) of Regulation S-K and the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K will be presented under the headings "Equity Compensation Stock Plans" and "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement, which information is incorporated by reference herein.

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

The information regarding certain relationships and related transactions required by Item 404 and Item 407(a) of Regulation S-K will be presented under the heading "Corporate Governance and Board Matters" in our Proxy Statement, which information is incorporated by reference herein.

Item 14. *Principal Accounting Fees and Services*

The information regarding our principal accounting fees and services required by Item 9(e) of Schedule 14A will be presented under the heading "Principal Accounting Fees and Services" in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.		Description
3.1	—	Restated Certificate of Incorporation, as supplemented (filed on August 6, 2009 as Exhibit 3.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
3.2	—	Restated By-Laws (filed on September 24, 2008 as Exhibit 3.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.1	—	Form of Senior Debt Indenture between Williams and Bank One Trust company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on September 8, 1997 as Exhibit 4.1 to The Williams Companies, Inc.'s Form S-3) and incorporated herein by reference.
4.2	—	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001 as Exhibit 4(k) to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
4.3	—	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed on May 9, 2002 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
4.4	—	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed February 25, 1997 as Exhibit 4.4.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3) and incorporated herein by reference.
4.5	—	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997) and incorporated herein by reference.

Exhibit No.		Description
4.6	—	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997) and incorporated herein by reference.
4.7	—	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998) and incorporated herein by reference.
4.8	—	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed on March 28, 2000 as Exhibit 4(q) to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
4.9	—	Indenture dated as of May 28, 2003, by and between The Williams Companies, Inc. and JPMorgan Chase Bank, as Trustee for the issuance of the 5.50% Junior Subordinated Convertible Debentures due 2033 (filed on August 12, 2003 as Exhibit 4.2 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
4.10	—	Indenture dated as of March 5, 2009, among The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A., as Trustee (filed on March 11, 2009 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.11	—	Registration Rights Agreement dated as of March 5, 2009 between The Williams Companies, Inc. and Citigroup Global Markets Inc. on behalf of themselves and the Initial Purchasers listed on Schedule I thereto (filed on March 11, 2009 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.12	—	Eleventh Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.13	—	First Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.2 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.14	—	Fifth Supplemental Indenture dated as of February 1, 2010 between The Williams Companies, Inc. and The Bank of New York Mellon Trust Company, N.A. (filed on February 2, 2010 as Exhibit 4.3 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.15	—	Amended and Restated Rights Agreement dated September 21, 2004 by and between The Williams Companies, Inc. and EquiServe Trust Company, N.A., as Rights Agent (filed on September 24, 2004 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.16	—	Amendment No. 1 dated May 18, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed on May 22, 2007 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.17	—	Amendment No. 2 dated October 12, 2007 to the Amended and Restated Rights Agreement dated September 21, 2004 (filed on October 15, 2007 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.18	—	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline's 7.125% Debentures, due 2025 (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline's Form S-3) and incorporated herein by reference.
4.19	—	Indenture dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline's $175 million aggregate principal amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline's Form 8-K) and incorporated herein by reference.

Exhibit No.		Description
4.20	—	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed on April 5, 2007 as Exhibit 4.1 to Northwest Pipeline Corporation's Form 8-K) (Commission File number 001-07414) and incorporated herein by reference.
4.21	—	Indenture dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP's Form 8-K) and incorporated herein by reference.
4.22	—	Registration Rights Agreement, dated as of May 23, 2008, among Northwest Pipeline GP and Banc of America Securities, LLC, BNP Paribas Securities Corp, and Greenwich Capital Markets, Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Northwest Pipeline GP's Form 8-K) and incorporated herein by reference.
4.23	—	Senior Indenture dated as of July 15, 1996 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on April 2, 1996 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-3) and incorporated herein by reference.
4.24	—	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on November 8, 2001 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form S-4) and incorporated herein by reference.
4.25	—	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed August 14, 2002 as Exhibit 4.1 to The Williams Companies Inc.'s Form 10-Q) and incorporated herein by reference.
4.26	—	Indenture dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line's $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K) and incorporated herein by reference.
4.27	—	Indenture dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K) and incorporated herein by reference.
4.28	—	Registration Rights Agreement, dated as of May 22, 2008, among Transcontinental Gas Pipe Line Corporation and Banc of America Securities LLC, Greenwich Capital Markets, Inc., and J.P. Morgan Securities Inc., acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on May 23, 2008 as Exhibit 10.1 to Transcontinental Gas Pipe Line Corporation's Form 8-K) and incorporated herein by reference.
4.29	—	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed on June 20, 2006 as Exhibit 4.1 to Williams Partners L.P. Form 8-K) and incorporated herein by reference.
4.30	—	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed on December 19, 2006 as Exhibit 4.1 to Williams Partners L.P. Form 8-K) and incorporated herein by reference.
4.31	—	Indenture dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
4.32	—	Registration Rights Agreement dated as of February 9, 2010, among Williams Partners L.P. and Barclays Capital Inc. and Citigroup Global Markets Inc., on behalf of themselves and the Initial Purchasers listed on Schedule I thereto (filed on February 10, 2010 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.1	—	The Williams Companies Amended and Restated Retirement Restoration Plan effective January 1, 2008 (filed on February 25, 2009 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference..

Exhibit No.		Description
10.2	—	The Williams Companies, Inc. 1996 Stock Plan (filed on March 27, 1996 as Exhibit A to The Williams Companies, Inc.'s Proxy Statement) and incorporated herein by reference.
10.3	—	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed on March 27, 1996 as Exhibit B to The Williams Companies, Inc.'s Proxy Statement) and incorporated herein by reference.
10.4	—	Form of Director and Officer Indemnification Agreement (filed on September 24, 2008 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.5*	—	Form of 2010 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.6*	—	Form of 2010 Restricted Stock Unit Agreement among Williams and certain employees and officers.
10.7*	—	Form of 2010 Nonqualified Stock Option Agreement among Williams and certain employees and officers.
10.8*	—	Form of 2009 Restricted Stock Unit Agreement among Williams and non-management directors.
10.9	—	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed on August 5, 2004 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.10	—	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.11 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.11	—	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan (filed on February 25, 2009 as Exhibit 10.12 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.12	—	The Williams Companies, Inc. 2007 Incentive Plan (filed on April 10, 2007 as Appendix C to The Williams Companies, Inc.'s Definitive Proxy Statement 14A) and incorporated herein by reference.
10.13	—	Amendment No. 1 to The Williams Companies, Inc. 2007 Incentive Plan (filed on February 25, 2009 as Exhibit 10.14 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.14	—	The Williams Companies, Inc. Employee Stock Purchase Plan (filed on April 10, 2007 as Appendix D to The Williams Companies, Inc.'s Definitive Proxy Statement 14A) and incorporated herein by reference.
10.15	—	Amendment No. 1 to The Williams Companies, Inc. Employee Stock Purchase (filed on February 25, 2009 as Exhibit 10.16 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference Plan .
10.16	—	Amendment No. 2 to The Williams Companies, Inc. Employee Stock Purchase Plan (filed on February 25, 2009 as Exhibit 10.17 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.17*	—	Amendment No. 3 to The Williams Companies, Inc. Employee Stock Purchase Plan.
10.18	—	Amended and Restated Change-in-Control Severance Agreement between the Company and certain executive officers (filed on February 25, 2009 as Exhibit 10.18 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference .
10.19	—	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed on May 15, 2007 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.

Exhibit No.		Description
10.20	—	Amendment Agreement dated November 21, 2007 among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline GP, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as administrative agent (filed on November 28, 2007 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.21	—	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent (filed on May 1, 2006 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.22	—	U.S. $500,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed on September 26, 2005 as Exhibit 10.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.23	—	U.S. $200,000,000 Five Year Credit Agreement dated September 20, 2005 among The Williams Companies, Inc., as Borrower, the Initial Lenders named herein, as Initial Lenders, the Initial Issuing Banks named herein, as Initial Issuing Banks and Citibank, N.A., as Agent (filed on September 26, 2005 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.24	—	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed on August 5, 2004 as Exhibit 10.2 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.25	—	Amendment No. 1 to the Master Professional Services Agreement dated June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation made as of June 1, 2004 (filed on August 5, 2004 as Exhibit 10.3 to The Williams Companies, Inc.'s Form 10-Q) and incorporated herein by reference.
10.26	—	Purchase and Sale Agreement, dated November 16, 2006, by and among Williams Energy Services, LLC, Williams Field Services Group, LLC, Williams Field Services Company, LLC, Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating, LLC (filed on November 21, 2006 as Exhibit 2.1 to Williams Partners L.P.'s Form 8-K) and incorporated herein by reference.
10.27	—	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners (filed on February 28, 2007 as Exhibit 10.41 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
10.28	—	Asset Purchase Agreement between Williams Power Company, Inc. and Bear Energy LP dated May 20, 2007 (filed on May 22, 2007 as Exhibit 99.1 to The Williams Companies, Inc.'s Form 8-K) and incorporated herein by reference.
10.29	—	Credit Agreement dated as of December 11, 2007, by and among Williams Partners L.P., the lenders party hereto, Citibank, N.A., as Administrative Agent and Issuing Bank, and The Bank of Nova Scotia, as Swingline Lender (filed on December 17, 2007 as Exhibit 10.5 to Williams Partners L.P. Form 8-K) and incorporated herein by reference.
10.30	—	Contribution Conveyance and Assumption Agreement, dated January 24, 2008, among Williams Pipeline Partners L.P., Williams Pipeline Operating LLC, WPP Merger LLC, Williams Pipeline Partners Holdings LLC, Northwest Pipeline GP, Williams Pipeline GP LLC, Williams Gas Pipeline Company, LLC, WGPC Holdings LLC and Williams Pipeline Services Company (filed on January 30, 2008 as Exhibit 10.2 to 1 to Williams Pipeline Partners L.P.'s Form 8-K) and incorporated herein by reference.

Exhibit No.		Description
10.31	—	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to The Williams Companies Inc.'s Form 8-K) and incorporated herein by reference.
10.32	—	Credit Agreement, dated as of February 17, 2010, by and among Williams Partners L.P., Transcontinental Gas Pipe Line Company, LLC, Northwest Pipeline GP, the lenders party thereto and Citibank, N.A., as Administrative Agent (filed on February 22, 2010 as Exhibit 10.5 to Williams Partners L.P.'s current report on Form 8-K) and incorporated herein by reference.
12*	—	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14	—	Code of Ethics for Senior Officers (filed on March 15, 2004 as Exhibit 14 to The Williams Companies, Inc.'s Form 10-K) and incorporated herein by reference.
21*	—	Subsidiaries of the registrant.
23.1*	—	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
23.2*	—	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
23.3*	—	Consent of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
24*	—	Power of Attorney.
31.1*	—	Certification of the Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	—	Certification of the Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	—	Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	—	Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
99.2*	—	Report of Independent Petroleum Engineers and Geologists, Miller and Lents, LTD.
101.INS**	—	XBRL Instance Document
101.SCH**	—	XBRL Taxonomy Extension Schema
101.CAL**	—	XBRL Taxonomy Extension Calculation Linkbase
101.DEF**	—	XBRL Taxonomy Extension Definition Linkbase
101.LAB**	—	XBRL Taxonomy Extension Label Linkbase
101.PRE**	—	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

** Furnished herewith

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.

THE WILLIAMS COMPANIES, INC.
(Registrant)

By: /s/ TED T. TIMMERMANS
Ted T. Timmermans
Controller

Date: February 25, 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.

Signature	Title	Date
/s/ STEVEN J. MALCOLM Steven J. Malcolm	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 25, 2010
/s/ DONALD R. CHAPPEL Donald R. Chappel	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2010
/s/ TED T. TIMMERMANS Ted T. Timmermans	Controller (Principal Accounting Officer)	February 25, 2010
/s/ JOSEPH R. CLEVELAND* Joseph R. Cleveland*	Director	February 25, 2010
/s/ KATHLEEN B. COOPER* Kathleen B. Cooper*	Director	February 25, 2010
/s/ IRL F. ENGELHARDT* Irl F. Engelhardt*	Director	February 25, 2010
/s/ WILLIAM R. GRANBERRY* William R. Granberry*	Director	February 25, 2010
/s/ WILLIAM E. GREEN* William E. Green*	Director	February 25, 2010
/s/ JUANITA H. HINSHAW* Juanita H. Hinshaw*	Director	February 25, 2010
/s/ W.R. HOWELL* W.R. Howell*	Director	February 25, 2010

Signature	Title	Date
/s/ GEORGE A. LORCH* George A. Lorch*	Director	February 25, 2010
/s/ WILLIAM G. LOWRIE* William G. Lowrie*	Director	February 25, 2010
/s/ FRANK T. MACINNIS* Frank T. MacInnis*	Director	February 25, 2010
/s/ JANICE D. STONEY* Janice D. Stoney*	Director	February 25, 2010
*By: /s/ LA FLEUR C. BROWNE La Fleur C. Browne *Attorney-in-Fact*		February 25, 2010

Corporate Data

ANNUAL MEETING
Stockholders are invited to our annual meeting at 11 a.m. Central Time on May 20, 2010, in the presentation theater, Williams Resource Center, One Williams Center, Tulsa, Okla.

INTERNET
Company information is available at www.williams.com.

INQUIRIES
To request additional materials, call 800-600-3782 or access our Web site.

Our investor relations group is available to answer questions about Williams. Call Sharna Reingold at 918-573-2078, or 800-600-3782. Direct your written inquiries to investor relations at our headquarters address below.

CORPORATE HEADQUARTERS
One Williams Center
Tulsa, OK 74172
Phone: 918-573-2000 or
toll-free, 800-WILLIAMS

WASHINGTON OFFICE
1627 Eye Street, N.W., Suite 900
Washington, D.C. 20006

TRANSFER AGENT AND REGISTRAR
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
Phone: 781-575-4706 or
toll-free, 800-884-4225
Hearing impaired: 800-952-9245
Internet: www.computershare.com

Send overnight mail to:
Computershare Trust Company, N.A.
250 Royall St.
Canton, MA 02021
Phone: 781-575-4706

Contact our transfer agent for information on registered share accounts, dividend payments or to receive information on our Direct Stock Purchase Plan.

AUDITORS
Ernst & Young LLP
Box 1529
Tulsa, OK 74101

CERTIFICATIONS
We submitted the certification of Steven J. Malcolm, our Chairman of the Board, Chief Executive Officer and President, to the New York Stock Exchange pursuant to NYSE Section 303A.12(a) on June 4, 2009.

We also filed with the Securities and Exchange Commission on February 26, 2010, as Exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2009, the certificates of our Chief Executive Officer and Chief Financial Officer as required by Section 302 of the Sarbanes-Oxley Act of 2002.

EQUAL OPPORTUNITY
The Company is an Equal Employment Opportunity (EEO) employer and does not discriminate in any employer/employee relations based on race, color, religion, sex, sexual orientation, national origin, age, disability or veteran's status.

CORPORATE RESPONSIBILITY
To view Williams' corporate responsibility report, go to www.williams.com.

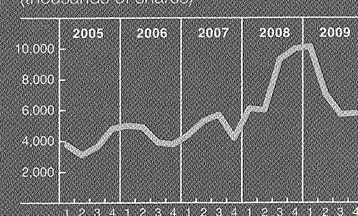
Stockholder Information

WILLIAMS SECURITIES
Williams common stock (WMB) is listed on the New York stock exchange.

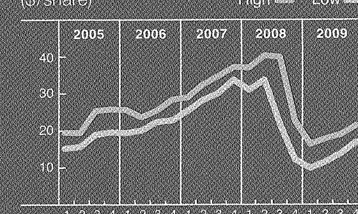
The market value on Feb. 19, 2010, was approximately $13.0 billion. On that date, 10,445 shareholders of record held 583,598,142 shares of Williams common stock. The company's common stock in 2009 traded at an average daily volume of 7.4 million shares.

WILLIAMS COMMON STOCK ACTIVITY
A dividend of ten cents per share was paid in the first quarter of 2008. A dividend of eleven cents per share was paid in the last three quarters of 2008 and all four quarters of 2009.

WMB AVERAGE DAILY VOLUMES TRADED
(thousands of shares)



WMB PRICE RANGES
($/share) High Low



WILLIAMS DAILY CLOSING PRICES
($/share)

	2009		2008	
	High	Low	High	Low
1st Quarter	16.31	9.83	36.99	30.96
2nd Quarter	17.82	11.53	40.31	33.65
3rd Quarter	18.98	13.83	39.90	21.85
4th Quarter	21.37	16.89	22.50	12.13

Ingenuity takes energy.®

Williams®