WILLIAMS COMPANIES INC
Form 10-K
February 25, 2009

Table of Contents

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

(Mark One)

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2008**

or

o	**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 þ No o

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

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

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

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 $23,344,993,927.

The number of shares outstanding of the registrant s common stock outstanding at February 19, 2009 was 579,213,365.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s Definitive Proxy Statement for the Registrant s 2009 Annual Meeting of Stockholders to be held on May 21, 2009, are incorporated into Part III, as specifically set forth in Part III.

THE WILLIAMS COMPANIES, INC.
FORM 10-K

TABLE OF CONTENTS

Table of Contents

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, the 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 2008, 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.

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.

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

Table of Contents

BUSINESS SEGMENTS

Substantially all our operations are conducted through our subsidiaries. To achieve organizational and operating efficiencies, our activities are 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 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 New Mexico, Wyoming and Colorado) and Mid-Continent (Oklahoma and Texas) 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 and Fort Worth basins. Over 99 percent of Exploration & Production s domestic reserves are natural gas. Our Exploration & Production segment also has international oil and gas interests, which include a 69 percent equity interest in Apco Argentina Inc., an oil and gas exploration and production company with operations in Argentina, and a 4 percent equity interest in Petrowayu S.A., a Venezuelan corporation that is the operator of a 100 percent interest in the La Concepcion block located in western Venezuela.

Exploration & Production s current proved undeveloped and probable reserves provide us with strong capital investment opportunities for several years into the future. Exploration & Production s goal is to drill its existing proved undeveloped reserves, which is comprised of approximately 43 percent of proved reserves, and to drill in areas of probable reserves adding to our proved reserves. In addition, Exploration & Production provides a significant amount of equity production that is gathered and/or processed by our Midstream facilities in the San Juan basin.

Information for our Exploration & Production segment relates only to domestic activity unless otherwise noted. 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.

Gas reserves and wells

The following table summarizes our U.S. natural gas reserves as of December 31 (using market prices on December 31 held constant) for the year indicated:

	2008	2007 (Bcfe)	2006
Proved developed natural gas reserves	2,456	2,252	1,945
Proved undeveloped natural gas reserves	1,883	1,891	1,756
Total proved natural gas reserves	4,339	4,143	3,701

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2008. 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 the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC, although Exploration & Production has not yet been required to file any information with respect to its estimated total reserves at December 31, 2008 with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable to those reported here due to special DOE reporting requirements, such as the requirement to report gross operated reserves only. In 2007 and 2006, the underlying estimated reserves for the DOE did not differ by more than 5 percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

Approximately 99 percent of our year-end 2008 United States proved reserves estimates were audited in each separate basin 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 by basin 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 Reserve Information promulgated by the Society of Petroleum Engineers. NSAI is satisfied with our methods and procedures in preparing the December 31, 2008 reserve estimates and saw nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, as prepared by us. Reserve estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust, which comprise approximately 1 percent of our total U.S. proved reserves, were prepared by Miller and Lents, LTD.

The SEC has revised its oil and gas reporting requirements effective for fiscal years ending on or after December 31, 2009, with early adoption prohibited. These changes include:

- Expanding the definition of oil and gas reserves and providing clarification of certain concepts and technologies used in the reserve estimation process.

- Allowing optional disclosure of probable and possible reserves and permitting optional disclosure of price sensitivity analysis.

- Modifying prices used to estimate reserves for SEC disclosure purposes to a 12-month average price instead of a single-day, period-end price.

Requiring 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 properties and reserves by basin

The table below summarizes 2008 activity and reserves for each of our areas, with further discussion following the table.

	Wells Drilled (Gross)	Wells Drilled (Operated)	Wells Producing (Gross)	Wells Producing (Net)	Wellhead Production (Net Bcfe)	Proved Reserves (Bcfe)	% of Total Proved Reserves
Piceance	687	646	3,163	2,894	238	3,095	71%
San Juan	95	37	3,129	852	55	523	12%
Powder River	703	366	5,407	2,465	84	390	9%
Mid-Continent	82	76	672	434	25	224	5%
Other	220	0	611	21	4	107	3%
Total	1,787	1,125	12,982	6,666	406	4,339	100%

Piceance basin

The Piceance basin is located in northwestern Colorado and is our largest area of concentrated development. During 2008 we operated an average of 26 drilling rigs in the basin. As of December 31, 2008, 15 of these rigs were the new high efficiency rigs designed to drill up to 22 wells from one location. This area has approximately 1,770 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 7 processing plants and associated treating facilities with an eighth plant that came on-line in February 2009, for a total capacity of 1.25 Bcfd. During 2008, these plants recovered approximately 69 million gallons of natural gas liquids (NGLs) 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.

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. Also included is exploration activity and other miscellaneous activity.

The following table summarizes our leased acreage as of December 31, 2008:

	Gross Acres	Net Acres
Developed	981,853	512,896
Undeveloped	1,269,350	661,568

Table of Contents

Operating statistics

We focus on lower-risk development drilling. Our development drilling success rate was approximately 99 percent in each of 2008, 2007 and 2006. The following table summarizes domestic drilling activity by number and type of well for the periods indicated:

Number of Wells	**Gross Wells**	**Net Wells**
Development:		
Drilled		
2008	1,783	1,050
2007	1,590	904
2006	1,783	954
Successful		
2008	1,782	1,050
2007	1,581	899
2006	1,770	948

We also successfully drilled four exploratory wells in 2008. In addition, two exploratory wells drilled in prior years were determined to be unsuccessful in 2008.

Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. Exploration & Production natural gas hedges for 2009 domestic natural gas production consist of NYMEX fixed price contracts of 106 MMcf/d (whole year) and approximately 490 MMcf/d in regional collars (whole year). Our natural gas production hedges in 2008 consisted of 70 MMcf/d in NYMEX fixed price hedges and 434 MMcf/d in regional collars. A collar is an option contract that sets a gas price floor and ceiling for a certain volume of natural gas. Hedging decisions are made considering the overall Williams commodity risk exposure and are not executed independently by Exploration & Production; there are expected future gas purchases for other Williams entities that when taken as a net position may offset price risk related to Exploration & Production s expected future gas sales. In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging with the banks and on natural gas reserves value. In June 2008, we amended this agreement to extend the facility through year end 2013.

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

	2008	**2007**	**2006**
Total net production sold (in Bcfe)	400.4	333.1	274.4
Average production costs including production taxes per (Mcfe) produced	$ 1.26	$ 0.98	$ 1.02
Average sales price per Mcfe	$ 6.39	$ 4.92	$ 5.24
Realized gain (loss) on hedging contracts	$ 0.09	$ 0.16	$ (0.73)

Acquisitions & divestitures

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In May 2008, we acquired certain undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin for $285 million. In July 2008, a third party exercised its contractual option to purchase, on the same terms and conditions, an interest in a portion of the acquired assets for $71 million. We received this $71 million in October 2008.

In September 2008, we increased our position in the Fort Worth basin by acquiring certain undeveloped leasehold acreage and producing properties for $147 million subject to post-closing adjustments. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation.

Through other transactions totaling approximately $111 million, Exploration & Production expanded its acreage position and producing properties in the Fort Worth basin in north-central Texas and also expanded its acreage position in the Highlands area of the Piceance basin and 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. 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 February 1, 2009, we own 789,291 trust units.

International exploration and production interests

We also have investments in international oil and gas interests. If combined with our domestic proved reserves, our international interests would make up approximately 3 percent of our total proved reserves.

Gas Pipeline

We own and operate, a combined total of approximately 14,000 miles of pipelines with a total annual throughput of approximately 2,700 trillion British Thermal Units 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 Natural Gas System, L.L.C. Gas Pipeline also includes WMZ.

Transco

Transco is an interstate natural gas transportation company that owns and operates a 10,100-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, 2008, 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 3.8 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.5 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 2008. 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 and operates the facility. 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 October 2008, the FERC approved Transco s request to abandon its Hester storage facility, which is not in operation. Hester is not included in the capacity described above. 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 are future pipeline projects for which we have customer commitments.

Sentinel Expansion Project

The Sentinel Expansion Project involves an 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 $200 million. Phase I was placed into service in December 2008. Phase II is expected to be placed into service by 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. The capital cost of the project is estimated to be up to approximately $37 million. Transco plans to place the project into service by May 2010.

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. The capital cost of the project is estimated to be $248 million. Transco plans to place the project into service in phases, in July 2010 and May 2011.

Operating statistics

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

	2008	**2007**	**2006**
	(In trillion British Thermal Units)		
Market-area deliveries:			
Long-haul transportation	753	839	795
Market-area transportation	969	875	817
Total market-area deliveries	1,722	1,714	1,612
Production-area transportation	188	190	247

Total system deliveries	1,910	1,904	1,859
Average Daily Transportation Volumes	5.2	5.2	5.1
Average Daily Firm Reserved Capacity	6.8	6.6	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, 2008, Northwest Pipeline s system, having long-term firm transportation agreements including peaking service of approximately 3.6 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 2008, Northwest Pipeline served a total of 136 transportation and storage customers. We transport and store 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 largest customer of Northwest Pipeline in 2008 accounted for approximately 20.7 percent of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline s total operating revenues in 2008. 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 2008 or are future pipeline projects for which we have customer commitments.

Colorado Hub Connection Project

Northwest Pipeline has proposed installing a new 27-mile, 24-inch diameter lateral to connect the Meeker/White River Hub near Meeker, Colorado to its mainline near Sand Springs, Colorado. This project is referred to as the Colorado Hub Connection (CHC Project). It is estimated that the construction of the CHC Project will cost up to $60 million with service targeted to commence in November 2009. Northwest Pipeline will combine the lateral capacity with 341 MDth per day of existing mainline capacity from various receipt points for delivery to Ignacio, Colorado, including approximately 98 MDth per day of capacity that was sold on a short-term basis. Approximately 243 MDth per day of this capacity is held by Pan-Alberta Gas under a contract that terminates on October 31, 2012.

In addition to providing greater opportunity for contract extensions for the short-term firm and Pan-Alberta capacity, the CHC Project provides direct access to additional natural gas supplies at the Meeker/White River Hub for Northwest Pipeline s on-system and off-system markets. Northwest Pipeline has entered into precedent agreements with terms ranging between eight and fifteen years at maximum rates for all of the short-term firm and Pan-Alberta capacity resulting in the successful re-contracting of the capacity out to 2018 and beyond. In September 2008, Northwest Pipeline filed an application for FERC certification and is awaiting necessary regulatory approvals. If Northwest Pipeline does not proceed with the CHC Project, Northwest

Pipeline will seek recovery of any shortfall in annual capacity reservation revenues from our remaining customers in a future rate proceeding. Northwest Pipeline does expect to collect maximum rates for the new CHC Project capacity commitments and seek approval to recover the CHC Project costs in any future rate case filed with the FERC.

Sundance Trail Expansion

In February 2008, Northwest Pipeline initiated an open season for the proposed Sundance Trail Expansion project that resulted in the execution of an agreement for 150 MDth per day of firm transportation service from the Meeker/White River Hub in Colorado for delivery to the Opal Hub in Wyoming. The project will include construction of 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 existing compression at the Vernal compressor station which will enhance the efficiency of Northwest Pipeline s system. The Sundance Trail Expansion will utilize available capacity on the CHC lateral and the existing Piceance lateral in conjunction with available and expanded mainline capacity. The Sundance Trail Expansion remains subject to certain conditions, including receiving the necessary regulatory approvals. Northwest Pipeline expects to collect maximum system rates, and will seek approval to roll-in the Sundance Trail Expansion costs in any future rate case filed with the FERC.

Operating statistics

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

	2008	2007	2006
	(In trillion British Thermal Units)		
Total Transportation Volume	781	757	676
Average Daily Transportation Volumes	2.1	2.1	1.8
Average Daily Reserved Capacity Under Long-Term Base Firm Contracts, excluding peak capacity	2.5	2.5	2.5
Average Daily Reserved Capacity Under Short-Term Firm Contracts(1)	.7	.8	.9

(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 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. 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, 2008, our equity investment in Gulfstream was $525 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 estimated capital cost of this project is $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 estimated capital cost of this expansion is $192 million, with Gas Pipeline s share being 50 percent of such costs.

Table of Contents

WMZ

WMZ was formed to own and operate natural gas transportation and storage assets. We currently own an approximate 45.7 percent limited partnership interest and a 2 percent general partner interest in WMZ. WMZ provides us with lower cost of capital that is expected to enable growth of our Gas Pipeline business. WMZ also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by the boards of directors of Williams and WMZ s general partner, allow us to retain control of the assets through our ownership interest in WMZ. A subsidiary of ours, Williams Pipeline GP LLC, serves as the general partner of WMZ. The initial asset of WMZ is a 35 percent interest in Northwest Pipeline.

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, Venezuela 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 natural gas and crude oil from the wellhead 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.

Some of our assets are owned through our interest in WPZ.

Key variables for our 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. 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 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 2008, these operations gathered and processed gas for approximately 230 gas gathering and processing customers. Our top six gathering and processing customers accounted for about 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 a deepwater floating production platform in the Gulf of Mexico. Our crude oil transportation revenues are typically volumetric-based fee arrangements. However, a substantial 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 sell the oil back to the producers 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 about 87 percent of our Exploration & Production group s wellhead production in this basin. Both our San Juan Basin and Southwest Wyoming 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 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 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;

- 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 the steam generated by gas-driven turbines to produce approximately 60 mega-watts per day of electricity which we primarily sell into the local electrical grid.

As we enter the Piceance Basin in Colorado, our initial infrastructure includes:

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 new Willow Creek processing plant (see expansion projects below) will process gas flowing through the Parachute Lateral in addition to processing gas from other sources. In an arrangement approved by the FERC, Midstream is leasing the pipeline to Gas Pipeline, who will continue to operate the Parachute Lateral until completion of a planned FERC abandonment filing;

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 two major expansion projects include the new Willow Creek facility and additional capacity at our Echo Springs facility.

The Willow Creek processing plant is a 450 MMcf/d cryogenic natural gas processing plant in western Colorado s Piceance Basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. The plant is designed to recover 25 Mbbls/d of NGLs and the plant s inlet processing capacity is expected to be full at start-up expected in late 2009.

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 expect to begin construction on the fourth train at Echo Springs during the second half of 2009 and to bring the additional capacity online during late 2010, subject to all applicable permitting.

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, 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 new 37-mile Blind Faith extension, 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, Markham, and Cameron Meadows processing plants with a combined daily inlet capacity of nearly 1,500 MMcf/d and NGL handling capacity of 65 Mbbls/d;

Canyon Station offshore gas production system fixed-leg 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 300 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 floating 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

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Since 1997, we have invested over $1.5 billion in new midstream assets in the Gulf of Mexico. These facilities provide both onshore and offshore services through pipelines, platforms and processing plants. The new facilities could also attract incremental gas volumes to Transco s pipeline system in the southeastern United States.

Our current major expansion projects in the Gulf region include:

In the deepwater of the Gulf of Mexico, we completed construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith discovery located in Mississippi Canyon in the eastern deepwater of the Gulf of Mexico. The pipelines have been commissioned and production began flowing in the fourth quarter of 2008;

In the western deepwater of the Gulf of Mexico, we continued construction activities on our Perdido Norte project which will include an expansion of our onshore Markham gas processing facility and oil and gas lines that would expand the scale of our existing infrastructure.

Venezuela

Our Venezuelan investments involve gas compression and an equity interest in a gas processing and NGL fractionation operation. We own controlling interests and operate three gas compressor facilities which provide roughly 65 percent of the gas injections in eastern Venezuela. These facilities help stabilize the reservoir and enhance the recovery of crude oil by re-injecting natural gas at high pressures. The three gas compressor facilities, owned within two of our Venezuelan subsidiaries, had a net book value of $324 million at December 31, 2008 and are held as security on $177 million of non-recourse debt at December 31, 2008. We own controlling interests of 70% and 66.67% in these two subsidiaries.

Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of the Venezuelan state-owned oil company, Petróleos de Venezuela S.A. under long-term contracts. These significant contracts have a remaining term between 9 and 12 years and our revenues are based on a combination of fixed capital payments, throughput volumes and, in the case of one of the gas compression facilities, a minimum throughput guarantee. The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector. The continued threat of nationalization of certain energy-related assets in Venezuela could have a material negative impact on our results of operations. The economic situation resulting from lower commodity prices could jeopardize the Venezuelan oil industry and may further exacerbate political tension in Venezuela. We may not receive adequate compensation, or any compensation, if our assets in Venezuela are nationalized.

We also 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. Our equity investment had a book value of $69 million at December 31, 2008.

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. 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.

Our Canadian operations include an olefin liquids extraction plant located near Ft. McMurray, Alberta and an olefin fractionation facility near Edmonton, Alberta. Our facilities extract olefinic liquids from the off-gas produced by a third party oil sands bitumen upgrading process. Our arrangement with the third-party upgrade 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 olefins fractionator in western Canada and the only treater/processor of oil sands upgrader off-gas. These operations extract petrochemical feedstocks from upgrader off-gas streams allowing the upgraders to burn cleaner natural gas streams and reduce overall air emissions. The 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.

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 L.L.C. 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 Services 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 Mbbl/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 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.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2008	**2007**	**2006**
Volumes(1):			
Domestic gathering (TBtu)	1,013	1,045	1,181
Plant inlet natural gas (TBtu)	1,311	1,275	1,222

Domestic NGL production (Mbbls/d)(2)	154	163	152
Domestic NGL equity sales (Mbbls/d)(2)	80	92	88
Crude oil gathering (Mbbls/d)(2)	70	80	86
Canadian NGL equity sales (Mbbls/d)(2)	7	9	8
Olefin (ethylene and propylene) sales (millions of pounds)	1,605	1,401	988

(1) Excludes volumes associated with partially owned assets 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. We currently 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. 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.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which includes marketing and hedging the gas produced by Exploration & Production, and procuring fuel and shrink gas and hedging natural gas liquids 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, including certain legacy natural gas contracts and positions.

Gas Marketing s 2008 natural gas purchase volumes include 1.4Bcf/d of gas produced by Exploration & Production and another 1.0 Bcf/d from third party/other sources. This natural gas was in turn marketed and sold to third parties (2.0 Bcf/d) and to Midstream (.4 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.

As a result of the sale of a substantial portion of our Power business in the fourth quarter of 2007, Gas Marketing is also responsible for certain remaining legacy natural gas contracts and positions. During 2008, we substantially reduced the overall legacy positions remaining.

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; and

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.

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 non-owner 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. In 2007, Black Marlin filed and settled a major rate change application before the FERC, resulting in increased rates for service. In November 2007, Discovery filed a settlement in lieu of a rate change filing, which the FERC approved effective January 1, 2008, for all parties, except one protestor, Exxon Mobil Gas

Table of Contents

and Power Marketing Company. Among other things, the settlement increases Discovery s rates for service, although most volumes flowing before the settlement became effective are not affected by the rate change due to life of lease rates and commitments.

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 non-compliance 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 clean up 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; and
- 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. In 2005, we formed WPZ to help compete against other master limited partnerships for midstream projects. By virtue of the master limited partnership structure, WPZ provides us with an alternative source of equity capital.

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, 2009, we had approximately 4,704 full-time employees including 924 at the corporate level, 798 at Exploration & Production, 1,726 at Gas Pipeline, 1,232 at Midstream Gas & Liquids, and 24 at Gas Marketing Services. 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.

Table of Contents

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 statements discuss our expected future results based on current and pending business operations. 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, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements 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 NGL 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 project. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

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 costs of capital;

Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions (including the recent economic slowdown and the disruption of 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 the current geopolitical situation;

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 and

Additional risks described in our filings with the SEC.

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 Inherent to our Industry and Business

The long-term financial condition of our natural gas transportation 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 transportation 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, 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 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 our pipeline and cash flows associated with the 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, or if natural gas supplies are diverted to serve other markets, the overall volume of natural gas transported 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.

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; and

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 non-cash charge to earnings. The revisions could also possibly affect the evaluation of Exploration & Production s goodwill for impairment purposes. At December 31, 2008, 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 natural gas transportation 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 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 Pipelines rely on a limited number of customers for a significant portion of their revenues. The loss of even a portion of our contracted volumes, 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.

We are exposed to the credit risk of our customers.

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally our customers are rated investment grade, are otherwise considered credit worthy, are required to make pre-payments, or provide security to satisfy credit concerns. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers creditworthiness. While we monitor these situations carefully and attempt to take appropriate measures to protect ourselves, it is possible that we may have 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 operating results and financial condition.

The failure of new sources of natural gas production or liquid natural gas (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 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;
- Uncontrollable releases of oil, natural gas or well fluids;
- Pollution and other environmental risks;
- Natural disasters;
- Aging infrastructure;
- Damage inadvertently caused by third party activity, such as operation of construction equipment; and
- Terrorist attacks or threatened attacks on our facilities or those of other energy companies.

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 and 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 or 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 terrorism limits of $300 million per occurrence for property damage 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 the September 11, 2001 terrorist attacks and hurricanes Katrina, Rita, Gustav and Ike have impacted the availability of certain types of coverage at reasonable rates, 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 our growth in the gas pipeline and midstream business areas 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; and

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. The amount of expenses recorded for our defined benefit pension plans and other post-retirement benefit plans is also dependent on changes in several factors, including market interest rates and the returns on plan assets. Significant changes in any of these factors may adversely impact our future 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.

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 SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS 133) 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 Statement of Financial Accounting Standards (SFAS) 133, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to the Company has occurred during the applicable period.

The impact of changes in market prices for natural gas on the average gas prices received by us may be reduced based on the level of our hedging strategies. These hedging arrangements may limit our potential gains if the market prices for natural gas were to rise substantially over the price established by the hedge. In addition, our hedging arrangements expose us to the risk of financial loss in certain circumstances, including instances in which:

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

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 non-recourse 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. Recent events in certain South American countries, particularly the continued threat of nationalization of certain energy-related assets in Venezuela, could have a material negative impact on our results of operations. We may not receive adequate compensation, or any compensation, if our assets in Venezuela are nationalized.

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, sell 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. Our ability to comply with these covenants may be affected by many events beyond our control, and 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 and other related transactional documents 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. An event of default 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.

Events in the global credit markets created a shortage in the availability of credit and have led to credit market volatility.

In 2008, global credit markets experienced a shortage in overall liquidity and a resulting disruption in the availability of credit. While we cannot predict the occurrence of future disruptions or the duration of the current volatility in the credit markets, we believe cash on hand and cash provided by operating activities, as well as availability under our existing financing agreements will provide us with adequate liquidity. However, our ability to borrow under our existing financing agreements, including our bank credit facilities, could be negatively impacted if one or more of our lenders fail to honor its contractual obligation to lend to us. Continuing volatility or additional disruptions, including the bankruptcy or restructuring of certain financial institutions, may adversely affect the availability of credit already arranged and the availability and cost of credit in the future.

The continuation of recent economic conditions, including disruptions in the global credit markets, could adversely affect our results of operations.

The slowdown in the economy and the significant disruptions and volatility in global credit markets have 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 current credit ratings could impact our liquidity, access to capital and our costs of doing business, and maintaining current credit ratings is within 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; and
- 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 were raised to investment grade in 2007 by Standard & Poor s, Moody s Corporation, and Fitch Ratings, Ltd., and our senior unsecured debt ratings were raised to investment grade by Moody s and Fitch. 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.

Prices for natural gas liquids, 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 we receive for NGLs, natural gas, or other commodities, and the differences between prices of these commodities. Price volatility can 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;

Table of Contents

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; and

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.

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; and

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.

Costs of environmental liabilities and complying with existing and future environmental regulations, including those related to 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.

Compliance with environmental laws requires significant expenditures, including for clean up costs and damages arising out of contaminated properties. In addition, the possible failure to comply with environmental laws and regulations might result in the imposition of fines and penalties. 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 climate change create financial risk. The United States Congress and certain states have for some time been considering various forms of legislation related to greenhouse gas emissions. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate the emission of greenhouse gases. Numerous states have announced or adopted programs to stabilize and reduce greenhouse gases and similar federal legislation has been introduced in both houses of Congress. Our pipeline, exploration and production and gas processing facilities may be subject to regulation under climate change policies introduced at either the state or federal level within the next few years. There is a possibility that, when and if enacted, the final form of such legislation could increase our costs of compliance with environmental laws. If we are unable to recover or pass through all 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 greenhouse gases 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.

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.

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 2009, 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; and
- 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.

If third-party pipelines and other facilities interconnected to our pipeline and facilities become unavailable to transport 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 natural gas pipeline and storage facilities. 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 due to repairs, damage to the facility, lack of capacity, increased credit requirements or rates charged by such pipelines or facilities or for any other reason, our ability to operate efficiently and continue shipping natural gas to end-use markets could be restricted, 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 causing a material reduction in volumes transported on our pipeline 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 effective in April 2009 which will increase our costs of permitting and environmental compliance and may affect our ability to meet our anticipated drilling schedule and therefore 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, disputes over gas measurement, royalty payments, shareholder class action 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 Non-Core 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 may be unable to obtain insurance on commercially reasonable terms, if at all. 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.

Table of Contents

In addition, there is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risk. 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 31 states plus the District of Columbia in the United States and in Argentina, Canada and Venezuela.

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 1, 2009, are listed below.

Alan S. Armstrong	Senior Vice President, Midstream Age: 46 Position held since February 2002.

	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 of Williams Partners GP LLC, the general partner of Williams Partners L.P.
James J. Bender	Senior Vice President and General Counsel Age: 52 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.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 57 Position held since April 2003. Prior to joining us, Mr. Chappel held various financial, administrative and operational leadership positions. Mr. Chappel serves as a director of Williams Partners GP LLC, the general partner of Williams Partners L.P., and as 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: 53 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: 49 Position held since December 1998. Mr. Hill 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 Argentina Inc.
Steven J. Malcolm	Chairman of the Board, Chief Executive Officer and President Age: 60 Position held since September 2001. From May 2001 to September 2001, Mr. Malcolm was Executive Vice President of the Company. He was President and Chief Executive Officer of our subsidiary Williams Energy Services, LLC from December 1998 to May 2001 and Senior Vice President and General Manager of our subsidiary, Williams Field Services Company from November 1994 to December 1998. Mr. Malcolm serves as a director of 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 the Bank of Oklahoma, N.A.

Phillip D. Wright

Senior Vice President, Gas Pipeline
Age: 53

Position held since January 2005.

From October 2002 to January 2005, Mr. Wright 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 has held various positions with us since 1989. Mr. Wright serves as a director of Williams Pipeline GP LLC, the general partner of Williams Pipeline 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, 2009, we had approximately 10,323 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:

	2008			2007		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$ 36.99	$ 30.96	$ .10	$ 28.94	$ 25.32	$ .09
2nd	$ 40.31	$ 33.65	$ .11	$ 32.43	$ 28.20	$ .10
3rd	$ 39.90	$ 21.85	$ .11	$ 34.72	$ 30.08	$ .10
4th	$ 22.50	$ 12.13	$ .11	$ 37.16	$ 33.68	$ .10

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.

Table of Contents

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, 2004. The Bloomberg U.S. Pipeline Index is composed of Crosstex Energy, Inc., El Paso Corporation, Enbridge Inc., Kinder Morgan Management, LLC, National Fuel Gas Company, Oneok, Inc., Promigas S.A. E.S.P., 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

	2003	**2004**	**2005**	**2006**	**2007**	**2008**
The Williams Companies, Inc.	100.0	166.9	240.2	274.7	380.9	156.8
S&P 500 Index	100.0	110.9	116.3	134.7	142.1	89.5
Bloomberg U.S. Pipelines Index	100.0	130.9	173.3	200.9	238.2	145.5

Table of Contents

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

The following financial data at December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, 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, 2006 and 2005, and for the years ended December 31, 2005 and 2004, should be read in conjunction with the financial information included in Exhibit 99.1 of our Form 8-K as filed on October 12, 2007, except for the adjustments described in footnote (1) below. The following financial data at December 31, 2004, has been prepared from our accounting records.

	2008	2007	2006	2005	2004
		(Millions, except per-share amounts)			
Revenues(1)	$ 12,352	$ 10,486	$ 9,299	$ 9,690	$ 8,343
Income from continuing operations(2)	1,334	847	347	473	149
Income (loss) from discontinued operations(3)	84	143	(38)	(157)	15
Cumulative effect of change in accounting principles(4)				(2)	
Diluted earnings (loss) per common share:					
Income from continuing operations	2.26	1.40	.57	.79	.28
Income (loss) from discontinued operations	.14	.23	(.06)	(.26)	.03
Total assets at December 31	26,006	25,061	25,402	29,443	23,993
Short-term notes payable and long-term debt due within one year at December 31	196	143	392	123	250
Long-term debt at December 31	7,683	7,757	7,622	7,591	7,712
Stockholders equity at December 31	8,440	6,375	6,073	5,427	4,956
Cash dividends declared per common share	.43	.39	.345	.25	.08

(1) Prior period amounts reported for Exploration & Production have been adjusted to reflect the presentation of certain revenues and costs on a net basis. These adjustments reduced *revenues* and reduced *costs and operating expenses* by the same amount, with no net impact on segment profit. The reductions were $72 million in 2007, $77 million in 2006, $91 million in 2005 and $65 million in 2004.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales, impairments, and other accruals in 2008, 2007, and 2006. 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. Income from continuing operations for 2004 includes $94 million of income from a favorable arbitration award and $282 million of early debt retirement costs.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2008, 2007, and 2006 income (loss) from discontinued operations. The discontinued operations results for 2005 includes our former power business while 2004 includes the power business, the Canadian straddle plants, and the Alaska refining, retail, and pipeline operations.

(4) The 2005 *cumulative effect of change in accounting principles* 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).

Table of Contents

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

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: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), 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 2008

Our plan for 2008 was focused on continued disciplined growth. Objectives and highlights of this plan included:

Objectives	Highlights
Continuing to improve both EVA® and segment profit.	2008 segment profit of $2.9 billion, an increase of $749 million from 2007, contributed to improving our EVA®.
Continuing to increase natural gas production and reserves.	We invested $2.5 billion in capital expenditures in Exploration & Production, increasing average daily domestic production by approximately 20 percent over last year while adding 602 billion cubic feet equivalent in net reserves. Total year-end 2008 proved domestic natural gas reserves are 4.3 trillion cubic feet equivalent, up 5 percent from year-end 2007 reserves.
Increasing the scale of our gathering and processing business in key growth basins.	We invested $608 million in capital expenditures in Midstream, primarily Deepwater Gulf expansion projects and gas-processing capacity in the western United States.
Continue to invest in expansion projects on our interstate natural gas pipelines.	We invested $306 million in capital expenditures in Gas Pipeline during 2008.

Our 2008 *income from continuing operations* increased to $1.3 billion, as compared to $847 million in 2007. Our *net cash provided by operating activities* was almost $3.4 billion in 2008 compared to $2.2 billion in 2007.

While these annual measures are favorable compared to the prior year, the overall trend of results was significantly different when considering the first three quarters of the year versus the last quarter. Through September 30, 2008, our Exploration & Production business benefited from increased levels of production and higher net realized average natural gas prices, while our Midstream business realized higher margins from a favorable energy commodity price environment. However, energy commodity prices declined sharply during the last months of 2008, contributing to significantly lower fourth quarter operating results for these segments. The impact of the declining energy commodity prices on our consolidated results was partially mitigated by:

Strong earnings from Gas Pipeline, which benefited from new rates enacted during 2007, and the nature of its contracts;

Hedge positions at Exploration & Production related to a significant portion of its production;

Fee-based revenues from certain gathering and processing services at Midstream.

Table of Contents

See additional discussion in Results of Operations.

Other Significant 2008 Events

We completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors. (See Note 12 of Notes to Consolidated Financial Statements.)

Exploration & Production increased its positions by acquiring undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin and undeveloped leasehold acreage and producing properties in the Fort Worth basin. See additional discussion in Results of Operations Segments, Exploration & Production.

We recognized pre-tax income of $183 million in *income from discontinued operations* related to our former Alaska operations. (See Note 2 of Notes to Consolidated Financial Statements.)

Exploration & Production recognized pre-tax income of $148 million related to the sale of a contractual right to a production payment on certain future international hydrocarbon production. See additional discussion in Results of Operations Segments, Exploration & Production.

Williams Pipeline Partners L.P. completed its initial public offering. See additional discussion in Results of Operations Segments, Gas Pipeline.

In September 2008, Hurricanes Gustav and Ike impacted our operations, primarily at Midstream. As a result, we estimate that our segment profit for 2008 was decreased by approximately $60 million to $85 million due to downtime and charges for repairs and property insurance deductibles. See additional discussion in Results of Operations Segments, Gas Pipeline and Midstream Gas & Liquids.

The overall decline in equity markets in 2008 negatively impacted our employee benefit plan assets and will significantly increase our net periodic benefit expense in future periods. (See Note 7 of Notes to Consolidated Financial Statements.)

Outlook for 2009

We expect the overall economic recession and related lower energy commodity price environment as well as the challenging financial markets to continue throughout the year. This is expected to result in sharply lower results of operations and cash flow from operations compared to 2008 levels and could also result in a further reduction in capital expenditures. The impacts could include the future nonperformance of counterparties or impairments of goodwill and long-lived assets. Considering this environment, our plan for 2009 is built around the transition from significant growth to a focus on sustaining our current operations and reducing costs where appropriate. However, we believe we are well positioned to capture growth opportunities when commodity prices strengthen and as economic conditions improve. Although we expect a reduction in capital expenditures compared to the prior year, near-term investment in our businesses will remain significant and focused on completing major projects, meeting legal, regulatory, and/or contractual commitments, and maintaining a reduced level of natural gas production development.

We will 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 our gathering and processing and interstate natural gas pipeline systems, primarily through the completion of projects currently underway;

- Continuing to invest in our natural gas production development, although at a lower level than in recent years;
- 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.

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 drilling success or abandonment of projects by third parties served by Midstream and Gas Pipeline;
- Additional general economic, financial markets, or industry downturn;
- Changes in the political and regulatory environments;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 16 of Notes to Consolidated Financial Statements).

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, 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.

We have completed a review of potential changes to our company structure with a goal of enhancing shareholder value and determined to leave our company structure unchanged. Major factors in our decision were the sharp decline in energy commodity prices and a further deterioration in the macroeconomic environment since the initiation of the review in early November 2008. Our business mix and strong credit profile position us to weather the challenging economic and market conditions in 2009 and benefit as the economy recovers.

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 *Recent Accounting Standards* in Note 1 of Notes to Consolidated Financial Statements for further information on recently issued accounting standards.

Modernization of Oil & Gas Reporting Requirements

The SEC has revised its oil and gas reserves reporting requirements effective for fiscal years ending on or after December 31, 2009, with early adoption prohibited. These changes include:

- Expanding the definition of oil and gas reserves and providing clarification of certain concepts and technologies used in the reserve estimation process.
- Allowing optional disclosure of probable and possible reserves and permitting optional disclosure of price sensitivity analysis.

Modifying prices used to estimate reserves for SEC disclosure purposes to a 12-month average price instead of a single-day, period-end price.

Requiring 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.

Historically, the reserves calculated based on the SEC s reporting requirements were also used to calculate depletion on our producing properties, as required by SFAS 69, Disclosures about Oil and Gas Producing Activities (SFAS 69). However, the change in the SEC reporting requirements has not yet been adopted by the FASB. The SEC has announced its intent to discuss potential amendments to SFAS 69 with the FASB so that the reserves disclosed remain consistent with the reserves used to calculate depletion on our producing properties. Any such change would impact our future financial results. The SEC has indicated that it may delay the effective date of the revised reporting requirements if the FASB does not make conforming amendments by December 31, 2009.

Table of Contents

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.

Based on our assessment of the undiscounted and discounted cash flows on natural gas-producing properties and associated unproved leasehold costs in the Arkoma basin, Exploration & Production recorded an impairment charge of $129 million in December 2008. Significant judgments and assumptions in this impairment analysis included year-end natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, capital costs, and a pre-tax discount rate of 15 percent. The recorded impairment was largely the result of lower forward pricing estimates at year-end and lower reserve estimates resulting from lower year-end prices.

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 in other basins and utilized inputs consistent with those described above for the Arkoma basin. Certain assets within our Midstream segment were also evaluated for impairment utilizing judgments and assumptions including future fees, margins and volumes. The use of alternate judgments and/or 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 primarily resulting from a 2001 acquisition. We assess goodwill for impairment annually as of the end of the year. For purposes of our assessment, the reporting unit is Exploration & Production s domestic operations. As of December 31, 2008, 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.

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 reserve quantities of more than 4.3 Tcfe, natural gas prices, adjusted for locational differences, averaging approximately $5.80 per Mcfe and a pre-tax discount rate of 15 percent.

We further reviewed the estimated fair value of the stand-alone reporting unit by reconciling the sum of the fair values of all our businesses to our total market capitalization, including a control premium. In estimating the fair value of our businesses and a control premium, we considered a range of market comparables from historical sales transactions of energy companies. Market capitalization was based on our traded stock price for a reasonably short period of time before and after December 31, 2008. In evaluating these items in our reconciliation analysis, management considered a range of reasonable judgments. This reconciliation allowed management to consider market expectations in corroborating the reasonableness of the estimated stand-alone fair value of the Exploration & Production 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;

Recent operating losses or negative cash flows at the reporting unit level;

A decline in natural gas prices or reserve quantities;

Not meeting internal forecasts, or downward adjustments to future forecasts;

A decline in enterprise market capitalization below our 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. Further declines in natural gas prices would lower our estimates of fair value. 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 significant challenges affecting our businesses and the energy industry in 2009, these factors could impact us and require us to assess goodwill for possible impairment more frequently during 2009.

Subsequent to December 31, 2008, as a result of overall market and energy commodity price declines, we have witnessed periodic reductions in our total market capitalization below our December 31, 2008, consolidated stockholders equity balance. If our total market capitalization is below our consolidated stockholders equity balance at a future reporting date, we consider this an indicator of potential impairment of goodwill under recent SEC communications and our accounting considerations. We utilize market capitalization in corroborating our assessment of the fair value of our Exploration & Production reporting unit. Considering this, it is reasonably possible that we may be required to conduct an interim goodwill impairment evaluation, 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.

Table of Contents

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, 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-producing properties and/or goodwill and have an impact on our depletion expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual *depreciation, depletion and*

Table of Contents

amortization expense between approximately $46 million and $56 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, 2008, we have $639 million of deferred tax assets for which a $15 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 as required by FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). 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 regarding FIN 48.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Net periodic benefit expense and obligations 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

Table of Contents

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	$ (13)	$ 14	$ (133)	$ 154
Expected long-term rate of return on plan assets	(7)	7		
Rate of compensation increase	3	(3)	17	(17)
Other postretirement benefits:				
Discount rate	(2)	2	(32)	37
Expected long-term rate of return on plan assets	(1)	1		
Assumed health care cost trend rate	8	(6)	53	(42)

The expected long-term rates of return on plan assets are determined by combining a review of 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 as well as the weightings of each asset classification. The credit crisis and subsequent economic downturn have negatively impacted the markets and our 2008 investment returns largely mirror market performance. While the market downturn has impacted short-term investment performance, these expected rates of return are long-term in nature and are not significantly impacted by short-term market swings. 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 was 7.75 percent for 2006 through 2008 and 8.5 percent for 2003 through 2005. Over the past ten years, our actual average return on plan assets for our pension plans has been approximately 2.1 percent. The 2008 return on plan assets for our pension plans was a loss of approximately 34.1 percent, which significantly impacted the ten-year average rate of return on plan assets. The 2007 ten-year average rate of return on plan assets for the pension plans was approximately 7.7 percent. As described in Note 7 of Notes to Consolidated Financial Statements, the asset allocation is being changed during 2009 with a slightly higher percentage of plan assets being allocated to debt securities and cash and cash equivalents. Therefore, our 2009 expected long-term rate of return on plan assets assumption is expected to slightly decrease.

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 our actual historical cost rates that are adjusted for expected changes in the health care industry. An increase in this rate causes the other postretirement benefit obligation and expense to increase.

Fair Value Measurements

On January 1, 2008, we adopted SFAS No. 157, Fair Value Measurements (SFAS No. 157), for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 14 of Notes to Consolidated Financial Statements for disclosures regarding SFAS No. 157, including discussion of the fair value hierarchy levels and valuation methodologies.

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, 2008, 22 percent of the total assets measured at fair value and 2 percent of the total liabilities measured at fair value 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 also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, the existence of master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities. Currently, our approach is to 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 through 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, 2008, the credit reserve is $6 million on our net derivative assets and $15 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.

As of December 31, 2008, 77 percent of our derivatives portfolio expires in the next 12 months and 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 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.

The instruments included in Level 3 at December 31, 2008, predominantly consist of options that hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. The options are valued using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant input, implied volatility by location, is unobservable. The impact of volatility on changes in the overall fair value of the options structured as collars is mitigated by the offsetting nature of the put and call positions. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices. The hedges are accounted for as cash flow hedges where net unrealized gains and losses from changes in fair value are recorded, to the extent effective, in *other comprehensive income (loss)* and subsequently impact earnings when the underlying hedged production is sold.

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.

Table of Contents

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, 2008. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years Ended December 31,						
	2008 (Millions)	$ Change from 2007*	% Change from 2007*	2007 (Millions)	$ Change from 2006*	% Change from 2006*	2006 (Millions)
Revenues	$ 12,352	+1,866	+18%	$ 10,486	+1,187	+13%	$ 9,299
Costs and expenses:							
Costs and operating expenses	9,156	−1,149	−14%	8,007	−518	−7%	7,489
Selling, general and administrative expenses	504	−33	−7%	471	−82	−21%	389
Other (income) expense net	(82)	+64	NM	(18)	+52	NM	34
General corporate expenses	149	+12	+7%	161	−29	−22%	132
Securities litigation settlement and related costs					+167	+100%	167
Total costs and expenses	9,727			8,621			8,211
Operating income	2,625			1,865			1,088
Interest accrued net	(594)	+59	+9%	(653)			(653)
Investing income	191	−66	−26%	257	+89	+53%	168
Early debt retirement costs	(1)	+18	+95%	(19)	+12	+39%	(31)
Minority interest in income of consolidated subsidiaries	(174)	−84	−93%	(90)	−50	−125%	(40)
Other income net		−11	−100%	11	−15	−58%	26
Income from continuing operations before income taxes	2,047			1,371			558
Provision for income taxes	713	−189	−36%	524	−313	−148%	211
Income from continuing operations	1,334			847			347
Income (loss) from discontinued operations	84	−59	−41%	143	+181	NM	(38)

Net income	$ 1,418	$ 990	$ 309

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

2008 vs. 2007

Our consolidated results in 2008 have 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 natural gas liquid (NGL) production revenues resulting from higher average prices, partially offset by lower volumes. Additionally, Gas Marketing Services 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 2008 includes:

Gain of $148 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production;

Net gains of $49 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.

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 Services;

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 a contractual right to a production payment, partially offset by increased operating costs and $143 million of property impairments in 2008. The increase also reflects improved results at Gas Marketing Services 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.

Minority interest in income of consolidated subsidiaries increased primarily reflecting the growth in the minority interest holdings of Williams Partners L.P. and Williams Pipeline Partners L.P. in late 2007 and early 2008, respectively.

Table of Contents

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. 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 periods.

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

2007 vs. 2006

The increase in *revenues* is due primarily to higher Midstream revenues associated with increased NGL and olefins marketing revenues and increased production of olefins and NGLs. Exploration & Production experienced higher revenues also due to increases in production volumes and net realized average prices. Additionally, Gas Pipeline revenues increased primarily due to increased rates in effect since the first quarter of 2007. These increases are partially offset by a mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007.

The increase in *costs and operating expenses* is due primarily to increased NGL and olefins marketing purchases and increased costs associated with our olefins production business at Midstream. Additionally, Exploration & Production experienced higher depreciation, depletion and amortization and lease operating expenses due primarily to higher production volumes.

The increase in *SG&A* is primarily due to increased staffing in support of increased drilling and operational activity at Exploration & Production, the absence of a $25 million gain in 2006 related to the sale of certain receivables at Gas Marketing Services, and a $9 million charge related to certain international receivables at Midstream.

Other (income) expense net within *operating income* in 2006 includes:

- A $73 million accrual for a Gulf Liquids litigation contingency;
- Income of $9 million due to a settlement of an international contract dispute at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher employee-related costs, increased levels of charitable contributions and information technology expenses. The higher employee-related costs are primarily the result of higher stock compensation expense. (See Note 1 of Notes to Consolidated Financial Statements.)

The *securities litigation settlement and related costs* is primarily the result of our 2006 settlement related to class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002. (See Note 16 of Notes to Consolidated Financial Statements.)

The increase in *operating income* reflects record high NGL margins at Midstream, continued strong natural gas production growth at Exploration & Production, the positive effect of new rates at Gas Pipeline, and the absence of 2006 litigation expenses associated with shareholder lawsuits and Gulf Liquids litigation.

Interest accrued net includes a decrease of $19 million in interest expense associated with our Gulf Liquids litigation contingency, offset by changes in our debt portfolio, most significantly the issuance of new debt in December 2006 by Williams Partners L.P.

The increase in *investing income* is due to:

A $27 million increase in interest income primarily associated with larger cash and cash equivalent balances combined with slightly higher rates of return in 2007 compared to 2006;

Increased equity earnings of $38 million due largely to increased earnings of our Gulfstream Natural Gas System, L.L.C. (Gulfstream), Discovery Producer Services LLC (Discovery) and Aux Sable Liquid Products, L.P. (Aux Sable) investments;

The absence of a $16 million impairment in 2006 of a Venezuelan cost-based investment at Exploration & Production;

$14 million of gains from sales of cost-based investments in 2007.

These increases are partially offset by the absence of a $7 million gain on the sale of an international investment in 2006.

Early debt retirement costs in 2007 includes $19 million of premiums and fees related to the December 2007 repurchase of senior unsecured notes. *Early debt retirement costs* in 2006 includes $27 million in premiums and fees related to the January 2006 debt conversion and $4 million of accelerated amortization of debt expenses related to the retirement of the debt secured by assets of Williams Production RMT Company.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

Provision for income taxes was significantly higher in 2007 due primarily to higher pre-tax earnings. 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 periods.

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

Results of Operations   Segments

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

Exploration & Production

Overview of 2008

In 2008, segment revenues and segment profit for Exploration & Production improved significantly compared to 2007. The 2008 results benefited from higher production levels coupled with higher natural gas prices through the first three quarters of the year. However, the results were negatively impacted by a significant decline in natural gas prices in the fourth quarter. The potential impact of sustained lower natural gas prices is discussed further in the following *Outlook for 2009* section.

We ve remained focused on continuing our domestic development drilling program in our growth basins. Accordingly, we:

Benefited from increased domestic net realized average prices for the total year of 2008, which increased by approximately 28 percent compared to 2007. The domestic net realized average price for 2008 was $6.48 per thousand cubic feet of gas equivalent (Mcfe) compared to $5.08 per Mcfe in 2007. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses. The domestic net realized average price for the fourth quarter 2008 was $4.43 per Mcfe reflecting the significant decline in natural gas prices.

Increased average daily domestic production levels by approximately 20 percent compared to 2007. The average daily domestic production for 2008 was approximately 1,094 million cubic feet of gas equivalent (MMcfe) compared to 913 MMcfe in 2007. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

Drilled 1,783 gross domestic development wells in 2008 with a success rate of approximately 99 percent. This contributed to total net additions of 602 billion cubic feet equivalent (Bcfe) in net reserves a replacement rate for our domestic production of 148 percent. Capital expenditures for domestic drilling, development, and acquisition activity in 2008 were approximately $2.5 billion compared to $1.7 billion in

2007. Capital expenditures for 2008 include acquisitions in the Piceance and Fort Worth basins discussed in *Significant events* below.

The benefits of higher net realized average prices and higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to the impact of increased production volumes and prices on operating taxes and higher well service and lease service costs. In addition, higher production volumes coupled with higher capitalized drilling costs increased depreciation, depletion, and amortization expense.

Significant events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In May 2008, we acquired certain undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin for $285 million. A third party subsequently exercised its contractual option to purchase, on the same terms and conditions, an interest in a portion of the acquired assets for $71 million.

In September 2008, we increased our position in the Fort Worth basin by acquiring certain undeveloped leasehold acreage and producing properties for $147 million. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties.

Based on our assessment of undiscounted and discounted future cash flows, which considered year-end natural gas reserve quantities, we recorded an impairment of $129 million in December 2008 related to our properties in the Arkoma basin. In September 2008, we recorded a $14 million impairment due to unfavorable drilling results, also in the Arkoma basin.

In December 2008, the Wyoming Supreme Court ruled against us on our appeal of the Wyoming State Board of Equalization s decision to uphold an assessment by the Wyoming Department of Audit related to severance and ad valorem taxes for the years 2000 through 2002. Related to this decision, we adjusted our estimated liability for the periods from 2000 through 2008, which resulted in a charge of $34 million. (See Note 4 of Notes to Consolidated Financial Statements.)

Outlook for 2009

Considering the previously discussed significant decline in natural gas prices, we expect segment revenues and segment profit in 2009 to be significantly lower than in 2008. As a result, we plan to reduce capital expenditures and deploy fewer drilling rigs in 2009 compared to 2008 which will reduce the number of wells drilled. We have the following expectations and objectives for 2009:

Continuing our development drilling program in the Piceance, Fort Worth, Powder River and San Juan basins through our planned capital expenditures projected between $950 million and $1.05 billion.

Slight growth in our annual average daily domestic production level compared to 2008, with fourth quarter 2009 volumes likely to be less than the prior comparable period.

Declines in the costs of services and materials associated with development activities as demand for these resources decline. However, in the first quarter of 2009, we estimate we will incur between $25 million and

$35 million in expense from contract penalties associated with the reduction in drilling rigs deployed.

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production levels and demand, and the downturn in the global economy. A further significant decline in natural gas prices would impact these expectations for 2009.

In addition, changes in laws and regulations may impact our development drilling program. For example, the Colorado Oil & Gas Conservation Commission has enacted new rules effective in April 2009 which will increase our costs of permitting and environmental compliance and potentially delay drilling permits. The new rules include additional environmental and operational requirements before permit approvals are granted, tracking of certain chemicals brought on location, increased wildlife stipulations, new pit and waste management procedures and increased notifications and approvals from surface landowners.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production using NYMEX and basis fixed-price contracts and collar agreements.

For 2009, we have the following agreements and contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collar agreements	Rockies	150	$ 6.11 - $9.04
Collar agreements	San Juan	245	$ 6.58 - $9.62
Collar agreements	Mid-Continent	95	$ 7.08 - $9.73
NYMEX and basis fixed-price		106	$3.67

The following is a summary of our agreements and contracts for daily production for the years ended December 31, 2008, 2007 and 2006:

		2008		2007		2006	
		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	49	$6.50 - $8.25
Collars	NYMEX					15	$7.00 - $9.00
Collars	Rockies	170	$6.16 - $9.14	50	$5.65 -$7.45	50	$6.05 - $7.90
Collars	San Juan	202	$6.35 - $8.96	130	$5.98 - $9.63		
Collars	Mid-Continent	63	$7.02 - $9.72	76	$6.82 -$10.77		
NYMEX and basis fixed-price		70	$3.97	172	$3.90	299	$3.82

Additionally, we utilize contracted pipeline capacity through Gas Marketing to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also expect additional pipeline capacity to be put into service in 2009.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2008	2007	2006

	(Millions)		
Segment revenues	$ 3,121	$ 2,021	$ 1,411
Segment profit	$ 1,260	$ 756	$ 552

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 sold on behalf of 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 on behalf of certain outside parties, which is offset by a similar increase in *segment revenues*.

$143 million of property impairments in 2008 in the Arkoma basin as previously discussed.

$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 previously discussed.

$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 previously discussed sale of our Peru interests in 2008.

The $504 million increase in s*egment 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*.

2007 vs. 2006

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

$487 million, or 39 percent, increase in domestic production revenues reflecting $264 million associated with a 21 percent increase in production volumes sold and $223 million associated with a 15 percent increase in net realized average prices. The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance and Powder River basins. The impact of hedge positions on increased net realized average prices includes both the expiration of a portion of fixed-price hedges that are lower than the current market prices and higher than current market prices related to basin-specific collars entered into during the period. Production revenues in 2007 include approximately $53 million related to natural gas liquids. In 2006, approximately $29 million of similar revenues were classified within other revenues.

$144 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*.

These increases were partially offset by a $30 million unfavorable change related to hedge ineffectiveness due to $16 million in net unrealized losses from hedge ineffectiveness in 2007 compared to $14 million in net unrealized gains in 2006.

Total *segment costs and expenses* increased $409 million, primarily due to the following:

- $173 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs.

- $144 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*.

- $46 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well service expenses, facility expenses, equipment rentals, maintenance and repair services, and salt water disposal expenses.

- $36 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. In addition, we incurred higher insurance and information technology support costs related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods.

The $204 million increase in s*egment profit* is primarily due to the 21 percent increase in domestic production volumes sold as well as the 15 percent increase in net realized average prices, partially offset by the increase in *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. As a result, the recent decline in energy commodity prices has not significantly impacted our results of operations.

Significant events of 2008 include:

Gas Pipeline master limited partnership

In 2008, Williams Pipeline Partners L.P. completed its initial public offering. We own approximately 47.7 percent of the interests, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. We consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner. (See Note 1 of Notes to Consolidated Financial Statements.) Gas Pipeline s segment profit includes 100 percent of Williams Pipeline Partners L.P. s segment profit with the minority interest s share presented below segment profit.

Status of rate case

During 2006, Transco filed a general rate case with the FERC designed to recover increases in costs. The new rates were effective, subject to refund, on March 1, 2007. On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in their pending 2006 rate case. On March 7, 2008, the

FERC approved the agreement without modification. The agreement became effective June 1, 2008 and required refunds were issued in July 2008.

Hurricane Ike

In September 2008, Hurricane Ike impacted several onshore and offshore facilities on Transco s interstate natural gas pipeline system resulting in varying degrees of damage. However, Transco has continued to meet its customer commitments while running at lower-than-normal volumes. We expect the majority of associated costs will be recoverable through insurance, with the remainder recoverable through Transco s rates. We also expect the premiums for insuring our assets in the Gulf of Mexico region against weather events to significantly increase in 2009.

Gulfstream Phase III expansion project

In June 2007, our equity method investee, Gulfstream Natural Gas System, L.L.C. (Gulfstream), received FERC approval to extend its existing pipeline approximately 34 miles within Florida. Construction began in April 2008 and the expansion was placed into service in September 2008. The extension fully subscribed the remaining 345 Mdt/d of firm capacity on the existing pipeline. Gulfstream s estimated cost of this project is $118 million.

Gulfstream Phase IV expansion project

In September 2007, Gulfstream received FERC approval to construct 17.8 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. 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 estimated cost of this project is $192 million.

Sentinel expansion project

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 up to $200 million. We placed Phase I into service in December 2008 increasing capacity by 40 Mdt/d. Phase II will provide an additional 102 Mdt/d and is expected to be placed into service by November 2009.

Colorado Hub Connection project

In September 2008, we filed an application with the FERC to construct a 27-mile pipeline to provide increased access to the Rockies natural gas supplies. The estimated cost of the project is $60 million with service targeted to commence in November 2009. We will combine the lateral capacity with 341 Mdt/d of existing mainline capacity from various receipt points for delivery to Ignacio, Colorado, including approximately 98 Mdt/d of capacity that was sold on a short-term basis.

Outlook for 2009

In addition to the Gulfstream Phase IV compressor facility, Phase II of the Sentinel expansion project, and the Colorado Hub Connection project 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 2009.

Year-Over-Year Operating Results

Years Ended December 31,

	2008	2007 (Millions)	2006
Segment revenues	$ 1,634	$ 1,610	$ 1,348
Segment profit	$ 689	$ 673	$ 467

2008 vs. 2007

Segment revenues increased $24 million, or 1 percent, due primarily to a $52 million increase in transportation revenues resulting primarily from Transco s new rates, which were 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, due primarily 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 net changed unfavorably by $31 million due primarily 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 in 2008 on the sale of certain south Texas assets by Transco and a $9 million gain in 2008 on the sale of excess inventory gas.

The $16 million, or 2 percent, increase in *segment profit* is due primarily to the favorable changes in segment revenues and costs and operating expenses as well as slightly higher equity earnings from Gulfstream. These increases are partially offset by the unfavorable change in *other income net.*

2007 vs. 2006

Revenues increased $262 million, or 19 percent, due primarily to a $173 million increase in transportation revenues and a $25 million increase in storage revenues resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $59 million due to the sale of excess inventory gas.

Costs and operating expenses increased $86 million, or 11 percent, due primarily to:

An increase of $59 million associated with the sale of excess inventory gas;

An increase in depreciation expense of $30 million due to property additions;

An increase in personnel costs of $10 million due primarily to higher compensation as well as an increase in number of employees.

Partially offsetting these increases is a decrease of $12 million in contract and outside service costs and a decrease of $7 million in materials and supplies expense.

Other (income) expense net changed favorably by $15 million due primarily to $18 million of income associated with payments received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral. Also included in the favorable change is $17 million of income recorded in the second quarter of 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline, partially offset by $18 million of expense related to higher asset retirement obligations.

Equity earnings increased $14 million due primarily to a $14 million increase in equity earnings from Gulfstream. Gulfstream s higher earnings were primarily due to a decrease in property taxes from a favorable litigation outcome as well as improved operating results.

The $206 million, or 44 percent, increase in *segment profit* is due primarily to $262 million higher revenues, $14 million higher equity earnings and $15 million favorable *other (income) expense net* as previously discussed. Partially offsetting these increases are higher *costs and operating expenses* as previously discussed.

Table of Contents

Midstream Gas & Liquids

Overview of 2008

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 2008 include the following:

In the first three quarters of 2008, segment revenues and segment profit improved considerably compared to 2007. However, these results were followed by a steep decline in the fourth quarter due to a rapid decline in NGL and olefin prices. Compared to the prior year, our combined margins associated with the production and marketing of NGLs declined 70 percent in the fourth quarter and 15 percent for the year. Compared to the prior year, our combined margin from our olefin production and marketing business unit declined 81 percent in the fourth quarter and 18 percent for the year. The ongoing impact of sustained lower commodity prices is discussed further in the following Outlook for 2009 section.

Volatile commodity prices

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

During the first three quarters of 2008, strong per-unit NGL margins driven by higher crude prices, which impact NGL prices, in relationship to natural gas prices contributed significantly to our realized margins. During the fourth quarter, NGL and natural gas prices, along with most other energy commodities, were significantly impacted by the weakening economy and experienced a sharp decline. Although average annual natural gas prices increased from 2007 to 2008, we continued to benefit from favorable gas price differentials in the Rocky Mountain area which contributed to realized per-unit margins that were generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

Our average realized NGL per-unit margin at our processing plants during 2008 was 61 cents per gallon (cpg), compared to 55 cpg in 2007. The increase in our NGL per-unit margin is partially due to a change in the mix of NGL products sold. Due to third-party NGL pipeline capacity restrictions during the third quarter of 2008 and to unfavorable ethane economics in the fourth quarter of 2008, we reduced our recoveries of ethane in those periods.

Because we typically realize lower per-unit margins for ethane versus other NGLs, if we had produced the same mix of ethane and non-ethane NGLs during 2008 as we generally have in prior years, the average per-unit margin in 2008 would have been lower. NGL margins have exceeded our rolling five-year average for the last seven quarters, in spite of strong NGL margins in 2007 and early 2008 that have significantly increased our rolling five-year average from 26 cpg at the end of the 2007 to 37 cpg at the end of 2008.

NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants. Our domestic gathering and processing plants recognize NGL margins on our NGL equity volumes based upon market-based transfer prices to our NGL marketing business. The NGL marketing business transports and markets those equity volumes, and also markets NGLs on behalf of third-party NGL producers, including some of our fee-based processing customers, and the NGL volumes produced by Discovery Producer Services L.L.C. The NGL marketing business bears the risk of price changes in these NGL volumes while they are being transported to final sales delivery points, as well as the impact of lower of cost or market write-downs on ending inventory balances.

NGL marketing margins impacted by sharp decline in prices

In late 2007, the NGL marketing business sold the majority of our equity volumes in the West region to a third-party directly from the plants, which reduced our average inventory levels in the latter part of 2007. In early 2008, our NGL marketing business began to transport these volumes on a third-party pipeline for sale at downstream markets, which increased our inventory levels. Inventory volumes also increased during 2008 due to the previously discussed hurricane-related suspension of operations at a third-party fractionation facility at Mont Belvieu, Texas.

During 2006 and 2007, NGL price changes did not significantly affect in-transit inventory values. However in 2008 due to significantly and rapidly declining NGL prices, primarily during the fourth quarter, combined with higher average inventory levels, our NGL marketing business experienced a marketing loss of $78 million.

NGL sales volume constrained

Primarily during the third quarter of 2008, we experienced restrictions on the volume of NGLs we could deliver to third-party pipelines in our West region. These restrictions were caused by a lack of third-party NGL pipeline transportation capacity which resulted in us reducing our recovery of ethane to accommodate these restrictions. In the fourth quarter of 2008, these restrictions were alleviated as we were able to deliver NGL volumes from our Wyoming plants into the new Overland Pass NGL pipeline.

Due to unfavorable ethane economics during the fourth quarter of 2008, we elected to temporarily suspend ethane recoveries at certain plants which further reduced our NGL sales volumes. While reducing the recovery of ethane did benefit our overall average realized NGL per-unit margins as previously described, it negatively impacted our NGL volumes and operating profit.

Hurricanes Gustav and Ike

As a result of Hurricanes Gustav and Ike in September 2008, not only did our Gulf Coast region facilities experience reduced volumes and damage, but our West region was also negatively impacted. We estimate that our segment profit for 2008 was decreased by approximately $60 million to $85 million due to downtime and charges for repairs and property insurance deductibles associated with Hurricanes Gustav and Ike. Other than the Cameron Meadows natural gas processing plant and the Discovery offshore gathering system, our major gathering and processing assets in the Gulf of Mexico returned to full operations by the end of the third quarter. The Cameron Meadows plant sustained significant damage from Hurricane Ike. Operations are suspended while we evaluate the timing and extent of the required repairs. The Discovery offshore system, which we operate and own a 60 percent equity interest in, also sustained hurricane damage and was not accepting offshore gas from producers while repairs were being made. The mainline of the Discovery offshore system was repaired and returned to service in January 2009. In the West region, we had to store NGL inventories due to the hurricane-related suspension of operations at a third-party fractionation facility at Mont Belvieu, Texas. A portion of this inventory was sold in the fourth quarter of 2008, and we expect to sell the remaining excess inventory in 2009. While we expect business interruption insurance to largely mitigate any losses associated with outages beyond 60 days, the timing to resolve these claims is uncertain. We expect the cost of insuring our assets in the Gulf Coast region against weather events to significantly increase in 2009.

Williams Partners L.P.

We own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. We consolidate Williams Partners L.P. within the Midstream segment due to our control through the general partner. (See Note 1 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit, with the minority interest s share presented below segment profit.

Outlook for 2009

The following factors could impact our business in 2009.

Commodity price changes

> Margins in our NGL and olefins business are highly dependent upon continued demand within the global economy. NGL products are currently the preferred feedstock for ethylene and propylene olefin production, which are the building blocks of polyethylene or plastics. Forecasted domestic and global demand for polyethylene has weakened with the recent instability in the global economy. A continued slow down in domestic and global economies could further reduce the demand for the petrochemical products we produce in both Canada and the United States.
>
> As evidenced by recent events, NGL, crude and natural gas prices are highly volatile. NGL price changes have historically tracked with changes in the price of crude oil; however ethane prices have recently disassociated from crude prices. As NGL prices, especially ethane, decline, we expect lower per-unit NGL margins in 2009 compared to 2008. Additionally, we anticipate periods when it is not economical to recover ethane, which will further reduce our segment profit.
>
> Although natural gas prices declined significantly during the fourth-quarter of 2008, which reduced our costs associated with the production of NGLs, NGL margins were compressed as NGL prices fell more than natural gas prices. However, we expect continued favorable gas price differentials in the Rocky Mountain area to partially mitigate such per-unit margin declines.
>
> In our olefin production business, we continue to maintain a cost advantage as our propylene and ethylene olefin production processes use NGL-based feedstocks, which are less expensive than other olefin production processes that use alternative crude-based feedstocks. However, margins have narrowed and we anticipate results from our olefins production business for the 2009 year to be below 2008 levels.
>
> Fee-based revenues generally reduce our exposure to commodity price risks, but may also reduce our profitability compared to keep-whole arrangements in high margin environments. Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee-basis or a keep-whole or percent-of-liquids basis. If customers switch from keep-whole to fee-based processing, we expect a reduction in our NGL equity sales volumes in 2009 compared to 2008.

Gathering and processing volumes

Natural gas supplies supporting our gathering and processing volumes are dependent upon producer drilling activities. The current credit crisis and economic downturn, together with the low commodity price environment, are expected to reduce certain producer drilling activities. Although our customers in the West region are generally large producers and we anticipate they will continue with some level of drilling plans, certain reductions are expected in 2009. A significant decline in drilling activity would likely reduce our gathered volumes and volumes available for both fee-based and keep-whole processing.

We expect higher fee revenues, depreciation and operating expenses in our Gulf Coast region as our Devils Tower infrastructure expansions serving the Blind Faith and Bass Lite prospects move into a full year of operation in 2009. While we expect to continue to connect new supplies in the deepwater, this increase is expected to be partially offset by lower volumes in other Gulf Coast areas due to natural declines.

Allocation of capital to expansion projects

Given the current economic conditions and the volatility of the commodity price environment, we will continually prioritize and balance our capital expenditures against the demand for our services.

Completed expansion projects

In the eastern deepwater of the Gulf of Mexico, we completed construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. The pipelines have been commissioned and production began flowing in the fourth quarter of 2008.

Ongoing commitments

In the western deepwater of the Gulf of Mexico, we expect to spend $205 million on our major expansion projects in 2009, including the Perdido Norte project, which will include an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure. We expect this project to begin contributing to our segment profit at the end of 2009.

In the West Region, we expect to spend $260 million on our major expansion projects in 2009, including the Willow Creek facility and additional capacity at our Echo Springs facility.

Other factors for consideration

The current economic and commodity price environment may cause financial difficulties for certain of our customers. Many of our marketing counterparties are in the petrochemicals industry, which has been under severe stress from the current economic downturn. Although we actively manage our credit exposure through certain collateral or payment terms and arrangements, continued economic downturn may result in significant credit or bad debt losses.

We expect significant savings in certain NGL transportation costs in the West region due to the transition from our previous shipping arrangement to transportation on the Overland Pass pipeline. NGL volumes from our Wyoming plants began to flow into the Overland Pass pipeline in the fourth quarter of 2008, relieving pipeline capacity constraints and resulting in an expected increase in NGL volumes for 2009.

Our Venezuelan operations are operated for the exclusive benefit of the Venezuelan state-owned oil company, Petróleos de Venezuela S.A. (PDVSA). As energy commodity prices have sharply declined, PDVSA has failed to make regular payments to many service providers, including us. At December 31, 2008, we had a net receivable of $57 million from PDVSA, none of which was 60 days old or older at that date. This does not include $15 million owed to our 49 percent equity investee, Accroven, of which $5 million was 60 days old or older at December 31, 2008. We continue to monitor the situation and are actively seeking resolution with PDVSA. The collection of receivables from PDVSA has historically been slower and more time consuming than our other customers due to their policies and the political unrest in Venezuela. We expect, at this time, that the amounts will ultimately be paid. The failure of PDVSA to make payments to service providers, however, could jeopardize the Venezuelan oil industry and thereby unfavorably impact all service providers, including us.

In addition, the economic situation resulting from lower commodity prices may further exacerbate political tension in Venezuela. The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector. The continued threat of nationalization of certain energy-related assets in Venezuela could have a material negative impact on our results of operations. We may not receive adequate compensation for our interest in these assets, or any compensation, if our assets in Venezuela are nationalized. We own 70 percent and

66.67 percent controlling interests in the two subsidiaries that hold these assets. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the non-recourse debt related to these assets.

Year-Over-Year Operating Results

	Years Ended December 31, 2008	2007	2006
		(Millions)	
Segment revenues	$ 5,642	$ 5,180	$ 4,159
Segment profit (loss)			
Domestic gathering & processing	841	897	631
Venezuela	104	89	98
NGL Marketing, Olefins and Other	113	174	16
Indirect general and administrative expense	(95)	(88)	(70)
Total	$ 963	$ 1,072	$ 675

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.

2008 vs. 2007

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

A $210 million increase in revenues in our olefins production business due primarily 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 due primarily 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 $69 million increase in fee-based revenues due primarily to the West region, Venezuela, the deepwater Gulf Coast region and at our Conway fractionation and storage facilities.

Segment costs and expenses increased $569 million, or 14 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 due primarily to higher average natural gas prices.

A $126 million increase in NGL, olefin and crude marketing purchases due primarily to higher average NGL and crude prices, partially offset by lower volumes as discussed in the revenue section above. The increase also includes a $19 million higher charge in 2008 to write down the value of NGL and olefin inventories.

A $107 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 $44 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 related to the partial settlement of our Gulf Liquids litigation (see Note 16 of Notes to Consolidated Financial Statements).

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 due primarily 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 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 increases are partially offset by $18 million higher NGL margins and $8 million higher fee revenues due primarily to connecting new supplies in the deepwater.

Venezuela

Segment profit for our Venezuela assets increased due to higher fee revenues and lower bad debt expense, partially offset by lower currency exchange gains.

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 due primarily 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 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.

These increases are partially offset by:

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 related to the partial settlement of our Gulf Liquids litigation (see Note 16 of Notes to Consolidated Financial Statements).

2007 vs. 2006

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

A $528 million increase in revenues from the marketing of NGLs and olefins.

A $303 million increase in revenues from our olefins production business.

A $244 million increase in revenues associated with the production of NGLs.

These increases are partially offset by a $35 million decrease in fee revenues.

Segment costs and expenses increased $645 million, or 18 percent, primarily as a result of:

A $491 million increase in NGL and olefin marketing purchases.

A $257 million increase in costs from our olefins production business.

A $37 million increase in operating expenses including higher depreciation, maintenance, gathering fuel expenses and operating taxes.

$24 million higher general and administrative expenses.

A $10 million loss on impairment of the Carbonate Trend pipeline and an $8 million loss on impairment of other assets.

The absence of $11 million of net gains on the sales of assets in 2006.

These increases are partially offset by:

The absence of a 2006 charge of $73 million related to our Gulf Liquids litigation (see Note 15 of Notes to Consolidated Financial Statements).

A $95 million decrease in costs associated with the production of NGLs due primarily to lower natural gas prices.

$12 million income in 2007 from a favorable litigation outcome.

The increase in Midstream s *segment profit* reflects $339 million higher NGL margins and the absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006, as well as the other previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of Midstream s various operations is presented as follows.

Domestic gathering & processing

The increase in *domestic gathering and processing segment profit* includes a $308 million increase in the West region, partially offset by a $42 million decrease in the Gulf Coast region.

The increase in our West region s *segment profit* primarily results from higher NGL margins, higher processing fee based revenues and a favorable litigation settlement, partially offset by higher operating expenses and lower gathering fee revenues. The significant components of this increase include the following:

NGL margins increased $326 million in 2007 compared to 2006. This increase was driven by an increase in average per unit NGL prices, a decrease in costs associated with the production of NGLs reflecting lower natural gas prices and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant.

Processing fee revenues increased $12 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees.

$12 million income in 2007 from a favorable litigation outcome.

Gathering fee revenues decreased $6 million due primarily to natural volume declines and the shutdown of the Ignacio plant in the fourth quarter of 2007 as a result of the fire.

Operating expenses increased $21 million including $9 million in higher depreciation, $9 million in higher treating plant and gathering fuel due primarily to the expiration of a favorable gas purchase contract, $5 million related to gas imbalance revaluation losses in the current year compared to gains in the prior year, $5 million higher leased compression costs and $4 million higher costs related to the Jicarilla lease arrangement. These were partially offset by the absence of a $7 million accounts payable accrual adjustment in 2006 and $5 million in lower system product losses.

The decrease in the Gulf Coast region s *segment profit* is primarily a result of lower volumes from our deepwater facilities, losses on impairments, and the absence of gains on assets in 2006, partially offset by higher NGL margins and higher other fee revenues. The significant components of this decrease include the following:

Fee revenues from our deepwater assets decreased $40 million due primarily to declines in producers volumes.

A $10 million loss on impairment of the Carbonate Trend pipeline and a $6 million loss on impairment of our other assets.

The absence of $8 million in gains on the sales of certain gathering assets and a processing plant in 2006 and $5 million lower involuntary conversion gains resulting from insurance proceeds used to rebuild the Cameron Meadows plant.

NGL margins increased $14 million driven by higher NGL prices, partially offset by lower NGL recoveries and an increase in costs associated with the production of NGLs.

Other fee revenues increased $8 million driven by higher water removal fees.

Venezuela

Segment profit for our Venezuela assets decreased primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006, $6 million lower fee revenues due primarily to the discontinuance in 2007 of revenue recognition related to labor escalation receivables, $7 million higher operating expenses, and $8 million higher bad debt expense related to labor escalation receivables, partially offset by $19 million of higher currency exchange gains and $1 million higher equity earnings.

NGL marketing, olefins and other

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

The absence of the previously mentioned $73 million Gulf Liquids litigation charge in 2006.

$46 million in higher margins from our olefins production business due primarily to the increase in ownership of the Geismar olefins facility in July 2007 and higher prices of NGL products produced in our Canadian olefins operations.

$18 million in higher margins related to the marketing of olefins and $21 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006.

An $8 million reversal of a maintenance accrual (see below).

$9 million higher Aux Sable equity earnings primarily due to favorable processing margins.

$11 million higher Discovery equity earnings primarily due to higher NGL margins and volumes.

These increases are partially offset by:

$19 million in higher foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

The absence of a $4 million favorable transportation settlement in 2006.

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 first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods, is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The increase in indirect general and administrative expense is due primarily to higher technical support services and other charges for various administrative support functions and higher employee expenses.

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 fuel and shrink gas and hedging natural gas liquids 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, including certain legacy natural gas contracts and positions.

Overview of 2008

Gas Marketing s operating results for 2008 were primarily driven by higher realized margins on both storage and transportation contracts in addition to favorable price movements on derivative positions executed to hedge the anticipated withdrawals of natural gas from storage. These gains were partially offset by adjustments made to the carrying value of the natural gas inventories in storage reflecting a decline in the price of natural gas.

Outlook for 2009

For 2009, 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.

Table of Contents

Year-Over-Year Operating Results

	Years Ended December 31, 2008	2007	2006
		(Millions)	
Realized revenues	$ 6,385	$ 4,948	$ 5,185
Net forward unrealized mark-to-market gains (losses)	27	(315)	(136)
Segment revenues	$ 6,412	$ 4,633	$ 5,049
Segment profit (loss)	$ 3	$ (337)	$ (195)

2008 vs. 2007

Realized revenues represent (1) revenue from the sale of natural gas and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues in*creased $1,437 million 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.

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 favorable change of $342 million 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 of SFAS No. 133. 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 $340 million 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.

2007 vs. 2006

Realized revenues decreased $237 million primarily due to a decrease in net financial settlements of derivative contracts. This is partially offset by an increase in physical natural gas revenue as a result of a 9 percent increase in natural gas sales volumes partially offset by a 6 percent decrease in average prices on physical natural gas sales.

Net forward unrealized mark-to-market gains (losses) changed unfavorably as a result of a $156 million loss related to a legacy derivative natural gas sales contract that was previously accounted for on an accrual basis under the normal purchases and normal sales exception of SFAS No. 133. In addition, losses on gas purchase contracts caused by a decrease in forward natural gas prices were greater in 2007 than in 2006.

Total *segment costs and expenses* decreased $274 million, primarily due to a decrease in costs and operating expenses reflecting a 7 percent decrease in average prices on physical natural gas purchases partially offset by a 4 percent increase in natural gas purchase volumes. The net decrease was also partially offset by:

A $20 million accrual for litigation contingencies in 2007.

The absence of a $25 million gain from the sale of certain receivables to a third party in 2006.

The $142 million unfavorable change in *segment profit (loss)* is primarily due to the loss recognized on a legacy derivative contract previously treated as a normal purchase and normal sale, a $20 million accrual for

Table of Contents

litigation contingencies and the absence of a $25 million gain from the sale of certain receivables, partially offset by an improvement in accrual earnings.

Other

Year-Over-Year Operating Results

	Years Ended December 31,		
	2008	2007	2006
		(Millions)	
Segment revenues	$ 24	$ 26	$ 27
Segment loss	$ (3)	$ (1)	$ (13)

2008 vs. 2007

The results of our Other segment are relatively comparable to the prior year.

2007 vs. 2006

The improvement in *segment loss* for 2007 is primarily driven by $5 million of net gains on the sale of land.

Management s Discussion and Analysis of Financial Condition and Liquidity

Overview

In 2008, 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.
- 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.

These investments were primarily funded through our cash flow from operations, which totaled nearly $3.4 billion for 2008.

During the latter part of 2008, global credit markets experienced significant instability, our market capitalization declined as markets witnessed significant reductions in value and energy commodity prices experienced significant and rapid declines. While we have periodically provided for incremental funding needs through the issuance of debt and/or the sale of master limited partnership units, these sources of funding were considered economically unfavorable at December 31, 2008. In consideration of our liquidity under these conditions, we note the following:

We have sharply reduced our forecasted levels of capital expenditures and have the flexibility to make further reductions if needed.

As of December 31, 2008, we have approximately $1.4 billion of cash and cash equivalents and approximately $2.5 billion of available credit capacity under our credit facilities, of which $400 million expires in April 2009 and $100 million expires in May 2009. Our primary $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.)

Outlook

For 2009, we expect operating results and cash flows to be sharply reduced from 2008 levels by the continued impact of lower energy commodity prices. This impact is somewhat mitigated by certain of our cash flow streams that are substantially insulated from sustained lower 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.

In addition, we expect certain costs for services and materials to decline in 2009 as demand for these resources declines.

Although the financial markets and energy commodity environment are expected to be depressed for at least the near term, 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, and utilization of our revolving credit facilities as needed. However, we may be opportunistic in accessing the capital markets to build additional liquidity. We estimate our cash flow from operations to be between $1.9 billion and $2.2 billion in 2009.

We estimate capital and investment expenditures will total $2,150 million to $2,450 million in 2009. Of this total, approximately two-thirds is considered nondiscretionary to meet legal, regulatory, and/or contractual requirements or to preserve the value of existing assets. Included within the total estimated expenditures for 2009 is $250 million to $300 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

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 year-end 2008 levels.
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 16 of Notes to Consolidated Financial Statements).

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 2009. As noted below, certain of our unsecured revolving and letter of credit facilities are scheduled to expire in 2009 and 2010. These facilities were originated primarily in support of our former power business.

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. While most of our sources are available to us at the parent level, others may be available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and Williams Pipeline Partners L.P., our master limited partnerships. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

In response to the challenges encountered by many financial institutions, the U.S. Government has provided substantial support to financial institutions, some of which are providers under our credit facilities. We continue to closely monitor the credit status of all providers under our credit facilities.

Available Liquidity

	Credit Facilities Expiration	Year Ended December 31, 2008 (Millions)
Cash and cash equivalents(1)		$ 1,439
Available capacity under our unsecured revolving and letter of credit facilities totaling $1.2 billion:		
$400 million facilities	April 2009	400
$100 million facilities	May 2009	100
$700 million facilities	September 2010	480
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility(2)	May 2012	1,359
Available capacity under Williams Partners L.P. s $450 million senior unsecured credit facility(3)	December 2012	188
		$ 3,966

(1) *Cash and cash equivalents* includes $30 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 $609 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) Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. We expect that the ability of both Northwest Pipeline and Transco to borrow under this facility is reduced by approximately $19 million each due to the bankruptcy of a participating bank. We also expect that our consolidated ability to borrow under this facility is reduced by a total of $70 million, including the reductions related to Northwest Pipeline and Transco. The available liquidity in the table above reflects this $70 million reduction. (See Note 11 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

Our primary credit facility contains financial covenants including the requirement that we not exceed stated debt to capitalization ratios. At December 31, 2008, we are significantly below the maximum allowed ratios (see Note 11 of Notes to Consolidated Financial Statements).

(3) This facility is only available to Williams Partners L.P. We expect that Williams Partners L.P. s ability to borrow under this facility is reduced by $12 million due to the bankruptcy of a participating bank. The available liquidity in the table above reflects this $12 million reduction. (See Note 11 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

This credit facility contains financial covenants related to Williams Partners L.P. s EBITDA to interest expense ratio and indebtedness to EBITDA ratio (all as defined in the credit agreement). At December 31, 2008, they are in compliance with these covenants. However, since the ratios are calculated on a rolling four-quarter basis, the ratios at December 31, 2008, do not reflect the full-year impact of lower commodity prices in the fourth quarter which have continued into 2009.

Williams Partners L.P. has a shelf registration statement, which expires in October 2009, available for the issuance of $1.17 billion aggregate principal amount of debt and limited partnership unit securities.

Table of Contents

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

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

Standard & Poor s rates our senior unsecured debt at BB+ and our corporate credit at BBB-with a stable ratings outlook. With respect to Standard & Poor s, 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.

Moody s Investors Service rates our senior unsecured debt at Baa3. On November 6, 2008, Moody s revised our ratings outlook to negative from stable. On February 23, 2009, Moody s revised our ratings outlook to stable from negative. With respect to Moody s, 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 ranking at the lower end of the category.

Fitch Ratings rates our senior unsecured debt at BBB . On November 6, 2008, Fitch revised our ratings outlook to evolving from stable. On February 24, 2009, Fitch revised our ratings outlook to stable from evolving. With respect to Fitch, 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.

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, 2008, we estimate that a downgrade to a rating below investment grade would have required us to post up to $400 million in additional collateral with third parties.

Sources (Uses) of Cash

	Years Ended December 31,		
	2008	2007	2006
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 3,355	$ 2,237	$ 1,890
Financing activities	(432)	(511)	1,103
Investing activities	(3,183)	(2,296)	(2,321)

Increase (decrease) in cash and cash equivalents	$	(260)	$	(570)	$	672

Operating Activities

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

$140 million of cash received 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).

$144 million of required refunds paid by Transco related to a general rate case with the FERC (see Results of Operations Segments, Gas Pipeline).

Our *net cash provided by operating activities* in 2007 increased from 2006 due primarily to the increase in our operating results and the absence of a $145 million securities litigation settlement payment in 2006. These increases are partially offset by increased income tax payments in 2007 and other changes in working capital.

Financing Activities

2008

We received $362 million from the completion of the Williams Pipeline Partners L.P. initial public offering (see Note 1 of Notes to Consolidated Financial Statements).

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 from debt transactions (see Note 11 of Notes to Consolidated Financial Statements).

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.

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.

2006

Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016.

Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016.

Williams Partners L.P. acquired our interest in Williams Four Corners LLC for $1.6 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of 7.5 percent senior unsecured notes due 2011, a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, $350 million of common and Class B units, and equity offerings of $519 million in net proceeds.

We paid $489 million to retire a secured floating-rate term loan due in 2008.

We paid $26 million in premiums related to the conversion of $220 million of 5.5 percent junior subordinated convertible debentures into common stock.

We paid $207 million of quarterly dividends on common stock for the year ended December 31, 2006.

Investing Activities

2008

Our net investment in property, plant and equipment totaled $3.3 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 (see Results of Operations Segments, Exploration & Production).

$148 million of cash received from Exploration & Production s sale of a contractual right to a production payment (see Note 4 of Notes to Consolidated Financial Statements).

We contributed $111 million to our investments, including $90 million related to our Gulfstream equity investment.

2007

Our net investment in property, plant and equipment 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.

2006

Our net investment in property, plant and equipment totaled $2.4 billion and was primarily related to Exploration & Production s drilling activity, mostly in the Piceance basin, and Northwest Pipeline s capacity replacement project.

We purchased $386 million and received $414 million from the sale of auction rate securities.

Off-balance sheet financing arrangements and guarantees of debt or other commitments

We have various other guarantees and commitments which are disclosed in Notes 3, 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.

Table of Contents

Contractual Obligations

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

	2009	2010-2011	2012-2013 (Millions)	Thereafter	Total
Long-term debt, including current portion:					
Principal(l)	$ 53	$ 994	$ 1,248	$ 5,611	$ 7,906
Interest	588	1,151	894	4,452	7,085
Capital leases	3	2			5
Operating leases	96	80	42	44	262
Purchase obligations(2)	1,299	1,342	1,209	2,405	6,255
Other long-term liabilities, including current portion:					
Physical and financial derivatives(3)(4)	575	606	296	196	1,673
Other(5)(6)		1			1
Total	$ 2,614	$ 4,176	$ 3,689	$ 12,708	$ 23,187

(1) The debt instruments in this table are classified by stated maturity date. See Note 11 of Notes to Consolidated Financial Statements for discussion of certain non-recourse debt of two of our Venezuelan subsidiaries that is in technical default and classified as current on our Consolidated Balance Sheet.

(2) Includes $3.7 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, 2008 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 $3.6 billion at December 31, 2008, 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 $75 million in 2008 and $56 million in 2007. In 2009, we expect to contribute approximately $77 million to these plans (see Note 7 of Notes to Consolidated Financial Statements). During 2008, we contributed $60 million to our tax-qualified pension plans which was greater than the minimum funding requirements. Although the 2008 economic downturn resulted in a significant decrease in the funded status of our tax-qualified pension plans, we expect to contribute approximately $60 million to these pension plans again in 2009, which is expected to be greater than the minimum funding requirements. Estimated future minimum funding requirements may vary significantly from historical requirements if investment returns do not return to expected levels. Future minimum funding requirements may also be impacted if actual results differ significantly from estimated results for assumptions

such as interest rates, retirement rates, mortality and other significant assumptions or by changes to current legislation and regulations.

(6) As of December 31, 2008, we have accrued approximately $79 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 38 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 $43 million, all of which are recorded as liabilities on our balance sheet at December 31, 2008. We will seek recovery of approximately $14 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2008, we paid approximately $10 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $11 million in 2009 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, 2008, 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. 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 $2 million in 2008 and are estimated to be between $5 million and $10 million through 2012. 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.

Table of Contents

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.

The tables below provide information about our interest rate risk-sensitive instruments as of December 31, 2008 and 2007. 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.

	2009	2010	2011	2012	2013	Thereafter(1)	Total	Fair Value December 31, 2008
				(Dollars in millions)				
Long-term debt, including current portion(4)(6):								
Fixed rate	$ 41	$ 27	$ 948	$ 971	$ 17	$ 5,566	$ 7,570	$ 6,011
Interest rate	7.6%	7.6%	7.6%	7.6%	7.5%	7.9%		
Variable rate	$ 12	$ 12	$ 7	$ 255	$ 5	$ 13	$ 304	$ 274
Interest rate(2)								

	2008	2009	2010	2011	2012	Thereafter(1)	Total	Fair Value December 31, 2007
				(Dollars in millions)				
Long-term debt, including current portion(4):								
Fixed rate	$ 53	$ 41	$ 27	$ 948	$ 971	$ 5,111	$ 7,151	$ 7,994
Interest rate	7.7%	7.7%	7.4%	7.4%	7.3%	7.7%		
Variable rate	$ 85	$ 12	$ 12	$ 7	$ 605(5)	$ 18	$ 739	$ 735
Interest rate(3)								

(1) Includes unamortized discount and premium.

(2) The interest rate at December 31, 2008, is LIBOR plus 0.76 percent.

(3) The interest rate at December 31, 2007 was LIBOR plus 0.75 percent.

(4) Excludes capital leases.

(5) Includes Transco s subsequent refinancing of its $100 million notes, due on January 15, 2008, under our $1.5 billion revolving credit facility. (See Note 11 of Notes to Consolidated Financial Statements.)

(6) The debt instruments in this table are classified by stated maturity date. See Note 11 of Notes to Consolidated Financial Statements for discussion of certain non-recourse debt of two of our Venezuelan subsidiaries that is in technical default and classified as current on our Consolidated Balance Sheet.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and natural gas liquids, 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 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. Derivative contracts designated as normal purchases or sales under SFAS No. 133 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 was a net liability of $29 million at December 31, 2008. Our value at risk for contracts held for trading purposes was $0.2 million at December 31, 2008, and $1 million at December 31, 2007. During the year ended December 31, 2008, our value at risk for these contracts ranged from a high of $3.3 million to a low of $0.2 million.

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
Gas Marketing Services	Natural gas purchases and sales

The fair value of our nontrading derivatives was a net asset of $511 million at December 31, 2008.

The value at risk for derivative contracts held for nontrading purposes was $33 million at December 31, 2008, and $24 million at December 31, 2007. During the year ended December 31, 2008, our value at risk for these contracts ranged from a high of $72 million to a low of $33 million. The increase in value at risk reflects the impact on our nontrading portfolio of the increase in volumes of Exploration & Production hedges in 2009 and 2010. Derivative contracts included in our assets and liabilities of discontinued operations are included in the nontrading portfolio, but these had a value at risk of zero for both periods.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS No. 133. Of the total fair value of nontrading derivatives, SFAS No. 133 cash flow hedges had a net asset value of $458 million as of December 31, 2008. 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.

Table of Contents

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 $17 million at December 31, 2008, and $24 million at December 31, 2007. 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 5 percent and 7 percent of our net assets at December 31, 2008 and 2007, respectively. These foreign operations do not have significant transactions or financial instruments denominated in other currencies. 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 $84 million at December 31, 2008.

Table of Contents

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

MANAGEMENT S 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, 2008, 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 believe that, as of December 31, 2008, 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.

Table of Contents

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, 2008, 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, 2008, 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, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008 of The Williams Companies, Inc. and our report dated February 23, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 23, 2009

Table of Contents

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, 2008 and 2007, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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 explained in Note 5 to the consolidated financial statements, effective January 1, 2007 the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109*.

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, 2008, 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 23, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 23, 2009

Table of Contents

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF INCOME

	Years Ended December 31,		
	2008	**2007**	**2006**
	(Millions, except per-share amounts)		
Revenues:			
Exploration & Production	$ 3,121	$ 2,021	$ 1,411
Gas Pipeline	1,634	1,610	1,348
Midstream Gas & Liquids	5,642	5,180	4,159
Gas Marketing Services	6,412	4,633	5,049
Other	24	26	27
Intercompany eliminations	(4,481)	(2,984)	(2,695)
Total revenues	12,352	10,486	9,299
Segment costs and expenses:			
Costs and operating expenses	9,156	8,007	7,489
Selling, general and administrative expenses	504	471	389
Other (income) expense net	(82)	(18)	34
Total segment costs and expenses	9,578	8,460	7,912
General corporate expenses	149	161	132
Securities litigation settlement and related costs			167
Operating income (loss):			
Exploration & Production	1,240	731	530
Gas Pipeline	630	622	430
Midstream Gas & Liquids	904	1,011	635
Gas Marketing Services	3	(337)	(195)
Other	(3)	(1)	(13)
General corporate expenses	(149)	(161)	(132)
Securities litigation settlement and related costs			(167)
Total operating income	2,625	1,865	1,088
Interest accrued	(653)	(685)	(670)
Interest capitalized	59	32	17
Investing income	191	257	168
Early debt retirement costs	(1)	(19)	(31)
Minority interest in income of consolidated subsidiaries	(174)	(90)	(40)
Other income net		11	26
Income from continuing operations before income taxes	2,047	1,371	558
Provision for income taxes	713	524	211

Income from continuing operations	1,334	847	347
Income (loss) from discontinued operations	84	143	(38)
Net income	$ 1,418	$ 990	$ 309
Basic earnings (loss) per common share:			
Income from continuing operations	$ 2.30	$ 1.42	$ .58
Income (loss) from discontinued operations	.14	.24	(.06)
Net income	$ 2.44	$ 1.66	$ .52
Weighted-average shares (thousands)	581,342	596,174	595,053
Diluted earnings (loss) per common share:			
Income from continuing operations	$ 2.26	$ 1.40	$ .57
Income (loss) from discontinued operations	.14	.23	(.06)
Net income	$ 2.40	$ 1.63	$ .51
Weighted-average shares (thousands)	592,719	609,866	608,627

See accompanying notes.

Table of Contents

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2008	December 31, 2007
	(Dollars in millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,439	$ 1,699
Accounts and notes receivable (net of allowance of $40 at December 31, 2008 and $27 at December 31, 2007)	941	1,192
Inventories	260	209
Derivative assets	1,464	1,736
Assets of discontinued operations	6	185
Deferred income taxes		199
Other current assets and deferred charges	301	318
Total current assets	4,411	5,538
Investments	971	901
Property, plant and equipment net	18,065	15,981
Derivative assets	986	859
Goodwill	1,011	1,011
Other assets and deferred charges	562	771
Total assets	$ 26,006	$ 25,061
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,059	$ 1,131
Accrued liabilities	1,170	1,158
Derivative liabilities	1,093	1,824
Liabilities of discontinued operations	1	175
Long-term debt due within one year	196	143
Total current liabilities	3,519	4,431
Long-term debt	7,683	7,757
Deferred income taxes	3,390	2,996
Derivative liabilities	875	1,139
Other liabilities and deferred income	1,485	933
Contingent liabilities and commitments (Note 16)		
Minority interests in consolidated subsidiaries	614	1,430
Stockholders equity:		
	613	608

Common stock (960 million shares authorized at $1 par value; 613 million shares issued at December 31, 2008, and 608 million shares issued at December 31, 2007)		
Capital in excess of par value	8,074	6,748
Retained earnings (deficit)	874	(293)
Accumulated other comprehensive loss	(80)	(121)
	9,481	6,942
Less treasury stock, at cost (35 million shares of common stock at December 31, 2008 and 22 million shares of common stock at December 31, 2007)	(1,041)	(567)
Total stockholders equity	8,440	6,375
Total liabilities and stockholders equity	$ 26,006	$ 25,061

See accompanying notes.

82

Table of Contents

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

	Common Stock	Capital in Excess of Par Value	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Other	Treasury Stock	Total
	(Dollars in millions, except per-share amounts)						
Balance, December 31, 2005	$ 579	$ 6,328	$ (1,136)	$ (298)	$ (5)	$ (41)	$ 5,427
Comprehensive income:							
Net income 2006			309				309
Other comprehensive income:							
Net unrealized gains on cash flow hedges, net of reclassification adjustments				394			394
Foreign currency translation adjustments				(4)			(4)
Minimum pension liability adjustment				(1)			(1)
Total other comprehensive income							389
Total comprehensive income							698
Adjustment to initially apply SFAS No. 158, net of tax:							
Pension benefits:							
Prior service cost				(4)			(4)
Net actuarial loss				(150)			(150)
Minimum pension liability				5			5
Other postretirement benefits:							
Prior service cost				(4)			(4)
Net actuarial gain				2			2
Issuance of common stock from 5.5% debentures conversion (Note 12)	20	193					213
Cash dividends Common stock ($.35 per share)			(207)				(207)
Repayment of stockholders notes					5		5
Stock-based compensation, including tax benefit	4	84					88
Balance, December 31, 2006	603	6,605	(1,034)	(60)		(41)	6,073
Comprehensive income:							

Net income 2007			990			990
Other comprehensive loss:						
Net unrealized losses on cash flow hedges, net of reclassification adjustments				(179)		(179)
Foreign currency translation adjustments				53		53
Pension benefits:						
Net actuarial gain				53		53
Other postretirement benefits:						
Prior service cost				1		1
Net actuarial gain				9		9
Total other comprehensive loss						(63)
Allocation of other comprehensive loss to minority interest				2		2
Total comprehensive income						929
Cash dividends Common stock ($.39 per share)			(233)			(233)
FIN 48 adjustment (Note 5)			(17)			(17)
Purchase of treasury stock (Note 12)					(526)	(526)
Stock-based compensation, including tax benefit	5	143				148
Other			1			1
Balance, December 31, 2007	608	6,748	(293)	(121)	(567)	6,375
Comprehensive income:						
Net income 2008			1,418			1,418
Other comprehensive income:						
Net unrealized gains on cash flow hedges, net of reclassification adjustments				455		455
Foreign currency translation adjustments				(76)		(76)
Pension benefits:						
Prior service cost				1		1
Net actuarial loss				(344)		(344)
Other postretirement benefits:						
Prior service cost				9		9
Net actuarial loss				(9)		(9)
Total other comprehensive income						36
Allocation of other comprehensive income to minority interest				5		5
Total comprehensive income						1,459
Cash dividends Common stock ($.43 per share)			(250)			(250)
Issuance of common stock from 5.5% debentures conversion	2	25				27

(Note 12)							
Conversion of Williams Partners L.P. subordinated units to common units (Note 12)		1,225					1,225
Purchase of treasury stock (Note 12)						(474)	(474)
Stock-based compensation, including tax benefit	3	67					70
Other		9	(1)				8
Balance, December 31, 2008	$ 613	$ 8,074	$ 874	$ (80)	$	$ (1,041)	$ 8,440

See accompanying notes.

83

Table of Contents

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31,		
	2008	2007	2006
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 1,418	$ 990	$ 309
Adjustments to reconcile to net cash provided by operations:			
Reclassification of deferred net hedge gains related to sale of power business		(429)	
Depreciation, depletion and amortization	1,310	1,082	866
Provision for deferred income taxes	611	370	154
Provision for loss on investments, property and other assets	166	162	26
Net (gain) loss on dispositions of assets and business	(36)	16	(23)
Gain on sale of contractual production rights	(148)		
Early debt retirement costs	1	19	31
Minority interest in income of consolidated subsidiaries	174	90	40
Amortization of stock-based awards	31	70	44
Cash provided (used) by changes in current assets and liabilities:			
Accounts and notes receivable	329	(122)	386
Inventories	(48)	29	31
Margin deposits and customer margin deposits payable	88	(135)	98
Other current assets and deferred charges	(76)	(10)	(30)
Accounts payable	(343)	26	(184)
Accrued liabilities	7	(200)	(110)
Changes in current and noncurrent derivative assets and liabilities	(121)	370	303
Other, including changes in noncurrent assets and liabilities	(8)	(91)	(51)
Net cash provided by operating activities	3,355	2,237	1,890
FINANCING ACTIVITIES:			
Proceeds from long-term debt	674	684	1,299
Payments of long-term debt	(665)	(806)	(777)
Proceeds from issuance of common stock	32	56	34
Proceeds from sale of limited partner units of consolidated partnerships	362	333	863
Tax benefit of stock-based awards	21	32	16
Dividends paid	(250)	(233)	(207)
Purchase of treasury stock	(474)	(526)	
Payments for debt issuance costs and amendment fees	(4)	(4)	(37)
Premiums paid on early debt retirements and tender offer		(27)	(26)
Dividends and distributions paid to minority interests	(122)	(75)	(36)
Changes in cash overdrafts		52	(25)
Other net	(6)	3	(1)
Net cash provided (used) by financing activities	(432)	(511)	1,103

INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(3,475)	(2,816)	(2,509)
Net proceeds from dispositions	119	12	23
Changes in accounts payable and accrued liabilities	81	(52)	105
Purchases of investments/advances to affiliates	(111)	(60)	(49)
Purchases of auction rate securities		(304)	(386)
Purchase of ARO trust investments	(31)		
Proceeds from sales of auction rate securities		353	414
Proceeds from sale of business	22	471	
Proceeds from sale of contractual production rights	148		
Proceeds from dispositions of investments and other assets	41	92	62
Proceeds from sale of ARO trust investments	14		
Other net	9	8	19
Net cash used by investing activities	(3,183)	(2,296)	(2,321)
Increase (decrease) in cash and cash equivalents	(260)	(570)	672
Cash and cash equivalents at beginning of year	1,699	2,269	1,597
Cash and cash equivalents at end of year	$ 1,439	$ 1,699	$ 2,269

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Argentina.

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), formerly Transcontinental Gas Pipe Line Corporation, 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 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, majority-owned natural gas compression facilities in Venezuela, 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 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 Exploration & Production have been adjusted to reflect the presentation of certain revenues and costs on a net basis. These adjustments reduced *revenues* and reduced *costs and operating expenses* by the same amount, with no net impact on segment profit. The reductions were $72 million in 2007 and $77 million in 2006.

Discontinued operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS No. 144), the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our former power business as discontinued operations. (See Note 2.) These operations 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

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the general partner in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, we consolidate Williams Partners L.P. within our Midstream segment.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline. Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, we consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner.

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, or otherwise exercise significant influence over operating and financial policies of the company.

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.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted cash

Current restricted cash is included in *other current assets and deferred charges* in the Consolidated Balance Sheet and consists primarily of collateral required by certain loan agreements for our Venezuelan operations, and escrow accounts established to fund payments required by our California settlement. (See Note 16.) Noncurrent restricted cash is included in *other assets and deferred charges* in the Consolidated Balance Sheet and relates primarily to certain borrowings by our Venezuelan operations as previously mentioned and letters of credit. We do not expect this cash to be released within the next twelve months. The current and noncurrent restricted cash is primarily invested in short-term money market accounts with financial institutions.

The classification of restricted cash is determined based on the expected term of the collateral requirement and not necessarily the maturity date of the investment.

Auction rate securities

An auction rate security is an instrument with a long-term underlying maturity, but for which an auction is conducted periodically, as specified, to reset the interest rate and allow investors to buy or sell the instrument. Our Consolidated Statement of Cash Flows reflects the gross amount of the *purchases of auction rate securities* and the *proceeds from sales of auction rate securities*. At December 31, 2008, we are no longer purchasing auction rate securities. Our remaining auction rate securities balance as of December 31, 2008, was $7 million.

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 collectibility 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. We determine the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method. We determine the cost of the remaining inventories primarily using the average-cost method. LIFO inventory at December 31, 2008, was $11 million.

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*.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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 have *goodwill* of approximately $1 billion at December 31, 2008 and 2007, 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.

Subsequent to December 31, 2008, as a result of overall market and energy commodity price declines, we have witnessed periodic reductions in our total market capitalization below our December 31, 2008, consolidated stockholders equity balance. If our total market capitalization is below our consolidated stockholders equity balance at a future reporting date, we consider this an indicator of potential impairment of goodwill under recent SEC communications and our accounting considerations. We utilize market capitalization in corroborating our assessment of the fair value of our Exploration & Production reporting unit. Considering this, it is reasonably possible that we may be required to conduct an interim goodwill impairment evaluation, 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.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 contracts. 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 changes in the fair value of a commodity derivative is governed by SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS No. 133), as amended and depends on whether the derivative has been designated in a hedging relationship and whether we have elected the normal purchases and normal sales exception. The accounting for the change in fair value 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*.

For commodity derivatives designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is reported in *other comprehensive income (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*. 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* 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*.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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;

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, 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 evaluated the indicators in EITF Issue No. 99-19 Reporting Revenue Gross as a Principal versus as an Agent, including 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 possible refunds upon final orders in pending rate proceedings with the FERC. We record estimates of rate refund liabilities considering our and other third-party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection 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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 natural gas liquids (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 in accordance with SFAS No. 144, 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 proved and unproven 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 unproven 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, based on historical experience or other information, is amortized over the average holding period. A majority of the costs of acquired unproven reserves are associated with areas to which proved developed producing reserves are also attributed. Generally, economic recovery of unproven 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

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

than in areas with limited or no prior drilling activity. Costs of acquired unproven 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

Compensation cost for share-based awards is based on the grant date fair value. Total stock-based compensation expense for the years ending December 31, 2008, 2007, and 2006, was $31 million, $70 million and $44 million, respectively, of which $1 million, $9 million and $3 million, respectively, is included in *income (loss) from discontinued operations*. Measured but unrecognized stock-based compensation expense at December 31, 2008, was approximately $57 million, which does not include the effect of estimated forfeitures of $3 million. This amount is comprised of approximately $7 million related to stock options and approximately $50 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Foreign currency translation

Certain of our foreign subsidiaries and equity method investees 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 and equity investees are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations and our share of the results of operations of our equity affiliates 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 *other comprehensive income (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.

Recent Accounting Standards

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 was effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS No. 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). On January 1, 2008, we applied SFAS No. 157 to our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 14 for discussion of the adoption. Beginning January 1, 2009, we will prospectively apply SFAS No. 157 fair value measurement guidance to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis when such fair value measurements are required. Had we not elected to defer portions of SFAS No. 157, fair value measurements for nonfinancial items occurring in 2008 where SFAS No. 157 would have been applied include long-lived assets measured at fair value for impairment purposes, measuring the fair value of a reporting unit for purposes of assessing goodwill for impairment and the initial measurement at fair value of asset retirement obligations.

In December 2007, the FASB issued SFAS No. 141(R) Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100 percent ownership in the acquiree. SFAS No. 141(R) also requires expensing of restructuring and acquisition-related costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS No. 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. We will apply this standard for any business combinations after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS No. 160). SFAS No. 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

consolidated balance sheet within stockholders equity as a separate component from the parent s equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS No. 160. SFAS No. 160 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS No. 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. Beginning January 1, 2009, we will apply SFAS No. 160 prospectively with the exception of the presentation and disclosure requirements which must be applied retrospectively for all periods presented.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, currently establishes the disclosure requirements for derivative instruments and hedging activities. SFAS No. 161 amends and expands the disclosure requirements of Statement 133 with enhanced quantitative, qualitative and credit risk disclosures. The Statement requires quantitative disclosure in a tabular format about the fair values of derivative instruments, gains and losses on derivative instruments and information about where these items are reported in the financial statements. Also required in the tabular presentation is a separation of hedging and nonhedging activities. Qualitative disclosures include outlining objectives and strategies for using derivative instruments in terms of underlying risk exposures, use of derivatives for risk management and other purposes and accounting designation, and an understanding of the volume and purpose of derivative activity. Credit risk disclosures provide information about credit risk related contingent features included in derivative agreements. SFAS No. 161 also amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to clarify that disclosures about concentrations of credit risk should include derivative instruments. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We plan to apply this Statement beginning in 2009. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. The application of this Statement will increase the disclosures in our Consolidated Financial Statements.

In June 2008, the FASB issued FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities . FSP No. EITF 03-6-1 requires that unvested share-based payment awards containing nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) be considered participating securities and included in the computation of earnings per share (EPS) pursuant to the two-class method of FASB Statement No. 128, Earnings per Share. FSP No. EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented shall be adjusted retrospectively to conform to this FSP. Early application is not permitted. This FSP will not have a material impact on our EPS attributable to the common stockholders.

In June 2008, the FASB issued EITF Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) is Indexed to an Entity s Own Stock (EITF 07-5). EITF 07-5 clarifies how to determine whether certain instruments or embedded features are indexed to an entity s own stock. EITF 07-5 provides that an entity should evaluate the instrument s settlement provisions and contingent exercise provisions, if any, to determine whether an equity-linked financial instrument (or embedded feature) is indexed to its own stock. EITF 07-5 concludes that contingent exercise and settlement provisions in equity-linked financial instruments (or embedded features) are consistent with being indexed to an entity s own stock if they are based on variables that would be inputs to a fair value option or forward pricing model and they do not increase the instruments exposure to those variables. The

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

final consensus requires that an entity apply the guidance in this Issue in its first fiscal year beginning after December 15, 2008, including interim periods within those fiscal years. Early application is prohibited. We have outstanding convertible debentures. This Issue will not have an impact on our Consolidated Financial Statements.

In September 2008, the FASB issued EITF 08-5, Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement (EITF 08-5). The objective of this Issue is to determine an issuer s unit of accounting for a liability issued with an inseparable third-party credit enhancement when it is measured or disclosed at fair value on a recurring basis. The issuer of a liability with a third-party credit enhancement that is inseparable from the liability shall not include the effect of the credit enhancement in the fair value measurement of the liability. An issuer shall disclose the existence of a third-party credit enhancement on its issued liability. In accordance with EITF 08-5, an issuer in considering their own credit in the fair value measurement of a liability would ignore any third-party guarantee, letter of credit, or other form of credit enhancement. This Issue shall be effective on a prospective basis in the first reporting period beginning on or after December 15, 2008. The effect of initially applying the guidance in this Issue shall be included in the change in fair value in the period of adoption. Earlier application is permitted. We will apply EITF 08-5 beginning January 1, 2009, and this Issue will not initially have a material impact on the valuation of our derivative liabilities.

In November 2008, the FASB issued EITF 08-6, Accounting for Equity Method Investments Considerations. The Issue clarifies that an equity method investor is required to continue to recognize an other-than temporary impairment of their investment in accordance with APB Opinion No. 18. Also, an equity method investor should not separately test an investee s underlying assets for impairment. However, an equity method investor should recognize their share of an impairment charge recorded by an investee. This Issue will be effective on a prospective basis in fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. Earlier application by an entity that has previously adopted an alternative accounting policy would not be permitted. Beginning January 1, 2009, we will apply the guidance provided in this Consensus as required.

In December 2008, the FASB issued FSP No. FAS 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets . This FSP amends FASB Statement No. 132 (revised 2003), Employers Disclosures about Pensions and Other Postretirement Benefits , to provide guidance on an employer s disclosures about plan assets of a defined benefit pension or other postretirement plan. FSP No. FAS 132(R)-1 applies to an employer that is subject to the disclosure requirements of Statement 132(R). An employer is required to disclose information about how investment allocation decisions are made, including factors that are pertinent to an understanding of investment policies and strategies. An employer should disclose separately for pension plans and other postretirement benefit plans the fair value of each major category of plan assets as of each annual reporting date for which a statement of financial position is presented. Asset categories should be based on the nature and risks of assets in an employer s plan(s). An employer is required to disclose information that enables users of financial statements to assess the inputs and valuation techniques used to develop fair value measurements of plan assets at the annual reporting date. For fair value measurements using significant unobservable inputs (Level 3), an employer should disclose the effect of the measurements on changes in plan assets for the period. An employer should provide users of financial statements with an understanding of significant concentrations of risk in plan assets. The disclosures about plan assets required by FSP No. FAS 132(R)-1 shall be provided for fiscal years ending after December 15, 2009. Upon initial application, the provisions of FSP No. FAS 132(R)-1 are not required for earlier periods that are otherwise presented for comparative purposes. Earlier application of the provisions of FSP No. FAS 132(R)-1 is permitted. We will assess the application of this Statement on our disclosures in our Consolidated Financial Statements.

Note 2. Discontinued Operations

The summarized results of discontinued operations and summarized assets and liabilities of discontinued operations primarily reflect our former power business except where noted otherwise. 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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized Results of Discontinued Operations

	2008	2007 (Millions)	2006
Revenues	$ 5	$ 2,436	$ 2,437
Income (loss) from discontinued operations before income taxes	$ 163	$ 392	$ (58)
(Impairments) and gain (loss) on sales	8	(162)	
(Provision) benefit for income taxes	(87)	(87)	20
Income (loss) from discontinued operations	$ 84	$ 143	$ (38)

Income (loss) from discontinued operations before income taxes for the year ended December 31, 2008, includes $140 million of gains from the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations and $54 million of income from a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank. (See Note 16.) These gains are partially offset by a $10 million charge from a settlement primarily related to the sale of natural gas liquids pipeline systems in 2002 and a charge of $11 million associated with an oil purchase contract related to our former Alaska refinery.

Income (loss) from discontinued operations before income taxes for the year ended December 31, 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 income* 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 income taxes* also includes the results of our former power business operations.

Income (loss) from discontinued operations before income taxes for the year ended December 31, 2006, includes charges of $19 million for an adverse arbitration award related to our former chemical fertilizer business, $6 million for a loss contingency in connection with a former exploration business, and $15 million associated with an oil purchase contract related to our former Alaska refinery. Partially offsetting these charges was $13 million of income related to the reduction of contingent obligations associated with our former distributive power business. *Income (loss) from discontinued operations before income taxes* also includes the results of our former power business operations.

(Impairments) and gain (loss) on sales for the year ended December 31, 2007, includes a pre-tax loss of approximately $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 under SFAS No. 133, 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.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized Assets and Liabilities of Discontinued Operations

	December 31, 2008	December 31, 2007
	(Millions)	
Derivative assets	$ 1	$ 114
Accounts receivable net	5	55
Other current assets		3
Total current assets	6	172
Property, plant and equipment net		8
Other noncurrent assets		5
Total noncurrent assets		13
Total assets	$ 6	$ 185
Derivative liabilities	$ 1	$ 114
Other current liabilities		61
Total current liabilities	1	175
Total liabilities	$ 1	$ 175

The December 31, 2008 and 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to the purchaser of our former power business, entirely offset by reciprocal positions with that same party. We continue to pursue assignment of the remaining contracts which are with one counterparty as of December 31, 2008.

Note 3. Investing Activities

Investing Income

	Years Ended December 31, 2008	2007	2006
	(Millions)		
Equity earnings*	$ 137	$ 137	$ 99
Income from investments*	1		

Impairments of cost-based investments	(4)	(1)	(20)
Interest income and other	57	121	89
Total investing income	$ 191	$ 257	$ 168

* Items also included in *segment profit*. (See Note 18.)

Impairments of cost-based investments for the year ended December 31, 2006, includes a $16 million impairment of a Venezuelan investment primarily due to a decline in reserve estimates. In 2006, our 10 percent direct working interest in an operating contract was converted to a 4 percent equity interest in a Venezuelan corporation which owns and operates oil and gas activities. Our 4 percent equity interest is reported as a cost method investment; previously, we accounted for our working interest using the proportionate consolidation method.

Interest income and other for the years ended December 31, 2008 and 2007, includes $10 million and $14 million, respectively, of gains from sales of cost-based investments.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Investments

	December 31, 2008	December 31, 2007
	(Millions)	
Equity method:		
Gulfstream Natural Gas System, L.L.C. 50%	$ 525	$ 439
Discovery Producer Services, L.L.C. 60%*	184	215
Petrolera Entre Lomas S.A. 40.8%	73	65
ACCROVEN 49.3%	69	62
Other	96	95
	947	876
Cost method	24	25
	$ 971	$ 901

* Our consolidated subsidiary, Williams Partners L.P., owns 60 percent. However, we continue to account for this investment under the equity method due to the voting provisions of Discovery s limited liability company, which provide the other member of Discovery significant participatory rights such that we do not control the investment.

Differences between the carrying value of our equity investments and the underlying equity in the net assets of the investees is primarily related to impairments previously recognized.

Dividends and distributions, including those presented below, received from companies accounted for by the equity method were $167 million in 2008 and $118 million in 2007. These transactions reduced the carrying value of our investments. These dividends and distributions primarily included:

	2008	2007
	(Millions)	
Gulfstream Natural Gas System, L.L.C.	$ 58	$ 34
Discovery Producer Services, L.L.C.	56	36
Aux Sable Liquid Products L.P.	28	22
Petrolera Entre Lomas S.A.	7	12

In addition, we contributed $90 million in 2008 and $38 million in 2007 to Gulfstream Natural Gas System, L.L.C. (Gulfstream).

Guarantees on Behalf of Investees

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN. These expire in January 2010 and have no carrying value.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at December 31, 2008 and 2007.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses from asset sales, impairments and other accruals or adjustments reflected in *other (income) expense net* within *segment costs and expenses.*

	Years Ended December 31,		
	2008	2007	2006
		(Millions)	
Exploration & Production			
Gain on sale of contractual right to an international production payment	$ (148)	$	$
Impairment of certain natural gas producing properties	143		
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 (see Note 16)	(32)		73
Involuntary conversion gain related to Ignacio plant	(12)		
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 $48 million in 2008, $5 million in 2007, and $5 million in 2006. The increase 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 natural gas producing properties

Based on a comparison of the estimated fair value to the carrying value, Exploration & Production recorded an impairment charge of $129 million in December 2008 related to properties in the Arkoma basin. Our impairment analysis included an assessment of undiscounted and discounted future cash flows, which considered year-end natural gas reserve quantities. Exploration & Production had previously recorded a $14 million impairment charge in 2008 due to unfavorable drilling results in the Arkoma basin.

Additional Item

In fourth-quarter 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.)

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 5. Provision for Income Taxes

The *provision for income taxes* from continuing operations includes:

	2008	2007 (Millions)	2006
Current:			
Federal	$ 179	$ 29	$ (9)
State	24	9	3
Foreign	35	46	43
	238	84	37
Deferred:			
Federal	466	422	146
State	(11)	(4)	4
Foreign	20	22	24
	475	440	174
Total provision	$ 713	$ 524	$ 211

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:

	2008	2007 (Millions)	2006
Provision at statutory rate	$ 717	$ 480	$ 195
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	8	4	7
Foreign operations net		18	23
Federal income tax litigation	(5)		(40)
Non-deductible convertible debenture expenses			10
Other net	(7)	22	16
Provision for income taxes	$ 713	$ 524	$ 211

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.

Utilization of foreign operating loss carryovers reduced the provision for income taxes by $13 million, $5 million and $3 million in 2008, 2007 and 2006, respectively.

Income from continuing operations before income taxes includes $196 million, $169 million, and $144 million of foreign income in 2008, 2007, and 2006, 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 tax filing positions, we apply the two-step process of recognition and measurement as required by FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). We adopted FIN 48 effective January 1, 2007. In association with this liability, we record an

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, and 2007, are as follows:

	2008	2007
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ 3,568	$ 3,192
Derivatives net	263	
Investments	163	176
Other	112	89
Total deferred tax liabilities	4,106	3,457
Deferred tax assets:		
Accrued liabilities	581	433
Derivatives net		173
Foreign carryovers	3	50
Minimum tax credits		8
Other	55	53
Total deferred tax assets	639	717
Less valuation allowance	15	57
Net deferred tax assets	624	660
Overall net deferred tax liabilities	$ 3,482	$ 2,797

The *valuation allowance* at December 31, 2008 and December 31, 2007, 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 $15 million of foreign deferred tax assets.

The reductions in foreign carryovers and the valuation allowance were primarily due to the restructuring of the European operations of our former power business.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2008, totaled approximately $377 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) were $155 million, $384 million, and $79 million in 2008, 2007, and 2006, respectively. Cash tax payments include settlements with taxing authorities associated with prior period audits of $47 million, $94 million, and $42 million in 2008, 2007 and 2006, respectively.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of December 31, 2008, we had approximately $79 million of unrecognized tax benefits. If recognized, approximately $70 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:

	2008	2007
	(Millions)	
Balance at beginning of period	$ 76	$ 93
Additions based on tax positions related to the current year	3	
Additions for tax positions for prior years	8	5
Reductions for tax positions of prior years	(8)	(19)
Settlement with taxing authorities		(3)
Lapse of applicable statute of limitations		
Balance at end of period	$ 79	$ 76

We recognize related interest and penalties as a component of income tax expense. Approximately $2 million and $60 million of interest and penalties were included in the provision for income taxes during 2008 and 2007, respectively. Approximately $81 million and $86 million of interest and penalties primarily relating to uncertain tax positions have been accrued as of December 31, 2008 and 2007, respectively.

As of December 31, 2008, the Internal Revenue Service (IRS) examinations of our consolidated U.S. income tax returns for 2006 and 2007 were in process. IRS examinations for 1997 through 2005 have been completed at the field level but the years remain open for certain unresolved 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 2003 through 2008. Certain Canadian entities are currently under examination.

During the next twelve months, we do not expect ultimate resolution of any unrecognized tax benefit associated with domestic or international matters to have a material impact on our financial position.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share for the years ended December 31, 2008, 2007 and 2006, are:

	2008	2007	2006
	(Dollars in millions, except per-share amounts; shares in thousands)		
	$ 1,334	$ 847	$ 347

Income from continuing operations available to common stockholders for basic and diluted earnings per common share(1)			
Basic weighted-average shares(2)(3)	581,342	596,174	595,053
Effect of dilutive securities:			
Nonvested restricted stock units	1,334	1,627	1,029
Stock options	3,439	4,743	4,440
Convertible debentures(3)	6,604	7,322	8,105
Diluted weighted-average shares	592,719	609,866	608,627
Earnings per common share from continuing operations:			
Basic	$ 2.30	$ 1.42	$ .58
Diluted	$ 2.26	$ 1.40	$ .57

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) The years ended December 31, 2008, 2007 and 2006, include \$2 million, \$3 million and \$3 million of interest expense, net of tax, associated with our convertible debentures. (See Note 12.) These amounts have been added back to *income from continuing operations 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 third-quarter 2008, we issued 2 million shares of our common stock in exchange for a portion of our 5.5 percent convertible debentures. During January 2006, we issued 20 million shares of common stock related to a conversion offer for our 5.5 percent convertible debentures.

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.

	2008	2007	2006
Options excluded (millions)	6.4	.8	3.6
Weighted-average exercise prices of options excluded	\$26.41	\$40.07	\$36.14
Exercise price ranges of options excluded	\$16.40 - \$42.29	\$36.66 -\$42.29	\$26.79 - \$42.29
Fourth quarter weighted-average market price	\$16.37	\$35.14	\$25.77

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 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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The sale of our power business in 2007 did not have a significant impact on our employee benefit plans. (See Note 2.)

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 896	$ 931	$ 284	$ 312
Service cost	23	23	2	3
Interest cost	60	54	18	17
Plan participants contributions			5	5
Benefits paid	(70)	(64)	(23)	(23)
Medicare Part D subsidy			2	
Plan amendment			(38)	
Actuarial (gain) loss	126	(48)	23	(30)
Benefit obligation at end of year	1,035	896	273	284
Change in plan assets:				
Fair value of plan assets at beginning of year	1,074	1,005	192	180
Actual return on plan assets	(360)	92	(62)	15
Employer contributions	61	41	14	15
Plan participants contributions			5	5
Benefits paid	(70)	(64)	(23)	(23)
Fair value of plan assets at end of year	705	1,074	126	192
Funded status overfunded (underfunded)	$ (330)	$ 178	$ (147)	$ (92)
Accumulated benefit obligation	$ 959	$ 838		

The net overfunded/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,

	2008	2007
	(Millions)	
Overfunded pension plans:		
Noncurrent assets	$	$ 203
Underfunded pension plans:		
Current liabilities	1	1
Noncurrent liabilities	329	24
Underfunded other postretirement benefit plans:		
Current liabilities	8	9
Noncurrent liabilities	139	83

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2008 benefit obligation *actuarial loss* of $126 million for our pension plans is due primarily to the impact of decreases in the discount rate utilized to calculate the benefit obligation and changes to the mortality assumptions. The 2007 benefit obligation *actuarial gain* of $48 million for our pension plans is due primarily to the impact of changes in the discount rate assumptions utilized to calculate the benefit obligation. The 2008 benefit obligation *actuarial loss* of $23 million for our other postretirement benefit plans is due primarily to the impact of the decrease in the discount rate used to calculate the benefit obligation and changes to the mortality assumptions. The 2008 other postretirement benefits *plan amendment* of $38 million is due to an increase in the retirees cost-sharing percentage within our subsidized retiree medical benefit plans. The 2007 benefit obligation *actuarial gain* of $30 million for our other postretirement benefit plans is due primarily to the impact of the increase in the discount rate used to calculate the benefit obligation and a decrease in the number of eligible participants in the plan.

At December 31, 2008, all of our pension plans had a projected benefit obligation and accumulated benefit obligation in excess of plan assets. At December 31, 2007, only our unfunded nonqualified pension plans had projected benefit obligations and accumulated benefit obligations in excess of plan assets. The projected benefit obligation of the unfunded nonqualified pension plans was $25 million and the accumulated benefit obligation was $22 million at December 31, 2007. There are no assets for these plans.

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 12 years for both our pension plans and 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	
	2008	2007	2008	2007
	(Millions)			
Amounts included in *accumulated other comprehensive loss*:				
Prior service (cost) credit	$ (5)	$ (6)	$ 12	$ (5)
Net actuarial gain (loss)	(708)	(156)	(8)	7
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:				

Prior service credit	N/A	N/A	$ 24	$ 3
Net actuarial gain (loss)	N/A	N/A	(57)	26

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, 2007, and 2006, consist of the following:

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
	(Millions)					
Components of net periodic benefit expense:						
Service cost	$ 23	$ 23	$ 22	$ 2	$ 3	$ 3
Interest cost	60	54	51	18	17	17
Expected return on plan assets	(79)	(73)	(67)	(13)	(12)	(11)
Amortization of prior service cost (credit)	1		(1)			
Amortization of net actuarial loss	13	19	21			
Amortization of regulatory asset		1		5	5	7
Net periodic benefit expense	$ 18	$ 24	$ 26	$ 12	$ 13	$ 16
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss):*						
Net actuarial (gain) loss	$ 565	$ (68)		$ 15	$ (15)	
Prior service credit				(16)		
Amortization of net actuarial loss	(13)	(19)				
Amortization of prior service cost	(1)			(1)	(2)	
Other changes in plan assets and benefit obligations recognized in *other comprehensive income (loss)*	551	(87)		(2)	(17)	
Total recognized in *net periodic benefit expense* and *other comprehensive income (loss)*	$ 569	$ (63)		$ 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, 2008, and include *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 2009 are as follows:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Amounts included in *accumulated other comprehensive loss*:		
Prior service cost (credit)	$ 1	$ (2)
Net actuarial loss	45	
Amounts included in *net regulatory assets* associated with our FERC-regulated gas pipelines:		
Prior service credit	N/A	$ (5)
Net actuarial loss	N/A	3

106

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, we have net regulatory assets of $26 million and at December 31, 2007, we had net regulatory liabilities of $28 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, 2008, and 2007, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.08%	6.41%	6.00%	6.40%
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, 2008, 2007, and 2006, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	2006	2008	2007	2006
Discount rate	6.41%	5.80%	5.65%	6.40%	5.80%	5.60%
Expected long-term rate of return on plan assets	7.75	7.75	7.75	7.00	6.97	6.95
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. 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.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The assumed health care cost trend rate for 2009 is 8.6 percent, and systematically decreases to 5.1 percent by 2018. 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	$ 3	$ (4)
Effect on other postretirement benefit obligation	53	(42)

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 following table presents the weighted-average asset allocations at December 31, 2008, and 2007 and target asset allocations at December 31, 2008, by asset category.

	Pension Benefits			Other Postretirement Benefits		
	2008	2007	Target	2008	2007	Target
Equity securities	78%	84%	84%	71%	79%	80%
Debt securities	17	12	16	17	12	20
Other	5	4		12	9	
	100%	100%	100%	100%	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 24 percent at December 31, 2008, and 40 percent at December 31, 2007, of the pension plans weighted-average assets, and 13 percent at December 31, 2008, and 29 percent at December 31, 2007, of the other postretirement benefit plans weighted-average assets. During 2008, a commingled fund held within the pension plans and the other postretirement benefit plans was replaced with direct investments in certain equity securities. Other assets are comprised primarily of cash and cash equivalents.

The assets are invested in accordance with the target allocations identified in the previous table. The investment policy provides for minimum and maximum ranges for the broad asset classes in the previous table. Additional target allocations are identified for specific classes of equity securities. The asset allocation ranges established by the investment policy are based upon a long-term investment perspective. The ranges are more heavily 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 significantly outperformed other asset classes over long periods of time. In December 2008, the Investment Committee voted to increase the percentage of assets allocated to debt securities and cash and cash equivalents, included within the other category in the previous table, to approximately 30-35 percent, as allowed in the investment policy. The reallocation is expected to be completed during the first quarter of 2009. The Investment Committee monitors the markets and asset allocations and at any time may adjust the allocation to debt securities and cash and cash equivalents downward, closer to the target asset allocation shown in the previous table.

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 except where these securities may be owned in a commingled investment

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

vehicle in which the pension plans trust invests. No more than five percent of the total stock portfolio valued at market may be invested in the common stock of any one corporation. 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 options or futures are also not authorized.

Debt security investments are restricted to high-quality, marketable securities that include U.S. Treasury, federal agencies and U.S. Government guaranteed obligations, 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 system. No more than five percent of the total portfolio at the time of purchase may be invested in the debt securities of any one issuer. U.S. Government guaranteed and agency securities are exempt from this provision.

During 2008, 11 active investment managers and one passive investment manager managed substantially all of the pension and other postretirement benefit plans funds. Each of the managers had responsibility for managing a specific portion of these assets.

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)	
2009	$ 44	$ 17	$ (2)
2010	38	18	(2)
2011	38	18	(2)
2012	42	18	(2)
2013	42	18	(2)
2014 - 2018	263	96	(13)

We expect to contribute approximately $61 million to our pension plans and approximately $16 million to our other postretirement benefit plans in 2009.

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 $24 million, $22 million, and $19 million in 2008, 2007, and 2006, respectively. 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. Since 2006 there have been no contributions to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock are no longer allowed within this defined contribution plan.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 8. Inventories

Inventories at December 31, 2008, and 2007, are as follows:

	2008	2007
	(Millions)	
Natural gas liquids	$ 56	$ 66
Natural gas in underground storage	97	45
Materials, supplies and other	107	98
	$ 260	$ 209

Inventories are primarily determined using the average-cost method.

Note 9. Property, Plant and Equipment

Property, plant and equipment net at December 31, 2008 and 2007, is as follows:

	Estimated Useful Life(b) (Years)	Depreciation Rates(b) (%)	2008	2007
			(Millions)	
Nonregulated				
Oil and gas properties	(a)		$ 8,749	$ 6,844
Natural gas gathering and processing facilities	3 - 40		5,394	4,781
Construction in progress	(d)		1,169	908
Other(c)	2 - 45		770	702
Regulated				
Natural gas transmission facilities		.01 - 7.25	8,441	8,208
Construction in progress		(d)	120	72
Other		.01 - 50	1,293	1,272
Total property, plant and equipment, at cost			25,936	22,787
Accumulated depreciation, depletion & amortization			(7,871)	(6,806)
Property, plant and equipment net			$ 18,065	$ 15,981

(a) 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 $571 million at December 31, 2008, and $378 million at December 31, 2007, of capitalized costs related to properties with unproven reserves not yet subject to depletion at Exploration & Production.

(b) Estimated useful life and depreciation rates are presented as of December 31, 2008.

(c) Certain assets above are currently pledged as collateral to secure debt. See Note 11 of Notes to Consolidated Financial Statements.

(d) Construction in progress balances not yet subject to depreciation.

Depreciation, depletion and amortization expense for *property, plant and equipment net* was $1.3 billion in 2008, $1.1 billion in 2007, and $863 million in 2006.

Regulated property, plant and equipment includes approximately $1.1 billion at December 31, 2008 and 2007 related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of our prior

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 asset retirement obligations at December 31, 2008 and 2007 are $644 million and $399 million, respectively. The increases in the obligations in 2008 are primarily due to revisions in our estimation of our asset retirement obligations in our Midstream and Gas Pipeline segments and increased asset additions in our Exploration and Production segment.

The 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, remove surface equipment and restore land 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.

SFAS No. 143 requires measurements of asset retirement obligations to include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market-risk premium. We have no examples of credit-worthy third parties in the energy industry who are willing to assume this type of risk for a determinable price. Therefore, because we cannot reasonably estimate such a market-risk premium, we excluded it from our estimates of ARO liabilities.

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 $13 million as of December 31, 2008.

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 approximately $95 million of these negative balances at December 31, 2008, and $96 million at December 31, 2007.

Accrued liabilities at December 31, 2008, and 2007, are as follows:

	2008	2007
	(Millions)	
Taxes other than income taxes	$ 223	$ 169
Interest	185	208
Employee costs	168	174

Income taxes	165	75
Accrual for Gulf Liquids litigation contingency*	51	94
Guarantees and payment obligations related to WilTel	38	39
Estimated rate refund liability	14	96
Other, including other loss contingencies	326	303
	$ 1,170	$ 1,158

* Includes interest of $14 million in 2008 and $25 million in 2007.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. Debt, Leases and Banking Arrangements

Long-Term Debt

Long-term debt at December 31, 2008 and 2007, is:

	Weighted-Average Interest Rate(1)	December 31, 2008(2)	2007
		(Millions)	
Secured(3)			
6.62%-9.45%, payable through 2016	8.0%	$ 123	$ 148
Adjustable rate, payable through 2016	3.9%	54	64
Capital lease obligations	6.0%	5	10
Unsecured			
5.5%-10.25%, payable through 2033(4)	7.6%	7,447	7,103
Revolving credit loans			250
Adjustable rate, payable through 2012	1.2%	250	325
Total long-term debt, including current portion		7,879	7,900
Long-term debt due within one year		(196)	(143)
Long-term debt		$ 7,683	$ 7,757

(1) At December 31, 2008.

(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.

(3) Includes $177 million and $212 million at December 31, 2008 and 2007, respectively, collateralized by certain fixed assets of two of our Venezuelan subsidiaries with a net book value of $324 million and $351 million at December 31, 2008 and 2007, respectively. The non-recourse debt at both subsidiaries is currently in technical default triggered by past due payments from their sole customer, Petróleos de Venezuela S.A. (PDVSA), under the related services contracts. We are in discussion with the associated lenders to obtain waivers. This has no impact on our other debt agreements or our liquidity.

(4) 2007 includes Transco s $100 million 6.25 percent notes, due on January 15, 2008, that were reclassified as long-term debt as a result of a subsequent refinancing under the $1.5 billion revolving credit facility.

Revolving credit and letter of credit facilities (credit facilities)

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. Lehman Commercial Paper Inc., which is committed to fund up to $70 million of our $1.5 billion credit facility, filed for bankruptcy in 2008. We expect that our ability to borrow under the credit facility is reduced by this committed amount. The committed amounts of other participating banks under this agreement remain in effect and are not impacted by the above. 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 WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2008, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 40 percent.

Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco. At December 31, 2008, they are in compliance with this covenant as their ratio of debt to capitalization, as calculated under this covenant, is approximately 36 percent for Northwest Pipeline and 26 percent for Transco.

We have unsecured $400 million, $100 million and $700 million credit facilities. The $400 million credit facility matures in April 2009, the $100 million credit facility matures in May 2009 and the $700 million credit facility matures in September 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 3.64 percent, 3.64 percent and 2.29 percent for the $400 million, $100 million and $700 million credit facilities, respectively, on the total committed amount of the facilities. In addition, we pay 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 trusts funded by the institutional investors. The assets of the trusts 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:

	$500 Million Facility		$700 Million Facility	
	$400 million	$100 million	$500 million	$200 million
Interest Rate	3.57 percent	LIBOR	4.35 percent	LIBOR
Facility Fixed Fee	3.19 percent		2.29 percent	

Williams Partners L.P. has an unsecured $450 million credit facility with a maturity date of December 2012. This $450 million credit facility is comprised initially of a $200 million credit facility available for borrowings and letters of credit and a $250 million term loan. Under certain conditions, the credit facility may be increased up to an additional $100 million. The parent company and certain affiliates of Lehman Brothers Commercial Bank, who is committed to fund up to $12 million of this credit facility, filed for bankruptcy in 2008. They expect that their ability to borrow under this credit facility is reduced by this committed amount. The committed amounts of the other participating banks under this agreement remain in effect and are not impacted by this reduction. 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, 2008, they 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, 2008, they are in compliance with this covenant as their ratio is 2.98.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Williams Partners L.P. is required to maintain an 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, 2008, they are in compliance with this covenant as their ratio is 5.13.

However, since the ratios are calculated on a rolling four-quarter basis, the ratios at December 31, 2008, do not reflect the full-year impact of lower commodity prices in the fourth quarter which have continued into 2009.

At December 31, 2008, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at December 31, 2008 (Millions)	
$500 million unsecured credit facilities	$	
$700 million unsecured credit facilities	$	220
$1.5 billion unsecured credit facility	$	71

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 and retirements

On January 15, 2008, Transco retired $100 million of 6.25 percent senior unsecured notes due January 15, 2008, with proceeds borrowed under our $1.5 billion unsecured credit facility.

On April 15, 2008, Transco retired a $75 million adjustable rate unsecured note due April 15, 2008, with proceeds borrowed under our $1.5 billion unsecured credit facility.

On May 22, 2008, Transco issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. A portion of these proceeds was used to repay Transco s $100 million and $75 million loans from January 2008 and April 2008, respectively, under our $1.5 billion unsecured credit facility. In September 2008, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

On May 22, 2008, Northwest Pipeline issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. These proceeds were used to repay Northwest Pipeline s $250 million loan from December 2007 under our $1.5 billion unsecured credit facility. In September 2008, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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)
2009(1)	$ 192
2010	
2011	927
2012	1,203
2013	

(1) Maturities for 2009 includes $177 million related to the non-recourse debt of two of our Venezuela subsidiaries. Only $38 million of this debt has a stated maturity in 2009, but the entire balance is reflected in 2009 as the debt is currently in technical default triggered by past due payments from their sole customer, PDVSA, under the related services contracts. We are in discussion with the associated lenders to obtain waivers. This has no impact on our other debt agreements or our liquidity.

Cash payments for interest (net of amounts capitalized) were as follows: 2008 $592 million; 2007 $634 million; and 2006 $611 million.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2008, are payable as follows:

	(Millions)
2009	$ 69
2010	53
2011	26
2012	23
2013	19
Thereafter	45
Total	$ 235

Total rent expense was $87 million in 2008 and $68 million in 2007 and 2006. Rent expense reported as discontinued operations, primarily related to a tolling agreement, was $148 million and $175 million in 2007 and 2006, respectively. Rent expense in discontinued operations was offset by approximately $276 million in 2007 and $264 million in 2006 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.

In November 2005, we initiated an offer to convert our 5.5 percent junior subordinated convertible debentures into our common stock. In January 2006, we converted $220 million of the debentures in exchange for 20 million

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

shares of common stock, a $26 million cash premium, and $2 million of accrued interest. During 2008, $27 million of debentures were exchanged for 2 million shares of common stock. At December 31, 2008, approximately $53 million of 5.5 percent junior subordinated convertible debentures, convertible into approximately 5 million shares of common stock, are outstanding.

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 minority interest on our Consolidated Balance Sheet rather than as equity. 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 first-quarter conversion, we recognized a decrease to minority interest and a corresponding increase to stockholders equity 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. Restricted stock units are valued at market value on the grant date of the award and generally vest over three years. 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 the grant and can be subject to accelerated vesting if certain future stock prices or if specific financial performance targets are achieved. Stock options generally expire 10 years after grant. 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. At December 31, 2007, 37 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 19 million shares were available for future grants.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 242 thousand shares at an average price of $17.80 per share during 2008. Approximately 1.7 million and 2 million shares were available for purchase under the ESPP at December 31, 2008 and 2007, 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. Stock options generally become exercisable over a three-year period from the date of grant and generally expire ten years after the grant.

The following summary reflects stock option activity and related information for the year ending December 31, 2008.

Stock Options	**Options (Millions)**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value (Millions)**
Outstanding at December 31, 2007	13.2	$ 16.62	
Granted	1.0	$ 36.50	
Exercised	(2.3)	$ 14.45	$ 49
Cancelled	(.4)	$ 33.44	
Outstanding at December 31, 2008	11.5	$ 18.10	$ 35
Exercisable at December 31, 2008	9.6	$ 15.44	$ 35

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $49 million, $74 million, and $36 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2008.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	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 $12.92	4.7	$ 7.12	4.1	4.7	$ 7.12	4.1
$12.93 to $23.72	3.8	$ 19.51	6.0	3.5	$ 19.32	5.8
$23.73 to $34.52	1.1	$ 28.11	7.5	.5	$ 27.79	6.6
$34.53 to $42.29	1.9	$ 37.06	5.4	.9	$ 37.64	1.4
Total	11.5	$ 18.10	5.3	9.6	$ 15.44	4.6

The estimated fair value at date of grant of options for our common stock granted in 2008, 2007, and 2006, using the Black-Scholes option pricing model, is as follows:

	2008	2007	2006
Weighted-average grant date fair value of options for our common stock granted during the year	$ 12.83	$ 9.09	$ 8.36
Weighted-average assumptions:			
Dividend yield	1.2%	1.5%	1.4%
Volatility	33.4%	28.7%	36.3%
Risk-free interest rate	3.5%	4.6%	4.7%
Expected life (years)	6.5	6.3	6.5

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 $32 million, $56 million and $34 million during 2008, 2007 and 2006, respectively. The tax benefit realized from stock options exercised during 2008 was $17 million, $27 million for 2007, and $14 million for 2006.

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, 2008.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock Units	**Shares (Millions)**	**Weighted-Average Fair Value***
Nonvested at December 31, 2007	4.4	$ 27.78
Granted	1.4	$ 30.13
Forfeited	(.2)	$ 27.52
Vested	(1.2)	$ 27.51
Nonvested at December 31, 2008	4.4	$ 22.91

* Performance-based shares are valued at the end-of-period market price until certification that the performance objectives have been completed. Upon certification, these shares are valued at that day s end-of-period market price. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2008	**2007**	**2006**
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$ 30.13	$ 30.79	$ 23.39
Total fair value of restricted stock units vested during the year ($ s in millions)	$ 48	$ 33	$ 15

Performance-based shares granted under the Plan represent 33 percent of nonvested restricted stock units outstanding at December 31, 2008. These grants are 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

Adoption of SFAS No. 157

SFAS No. 157, Fair Value Measurements (SFAS No. 157), establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. On January 1, 2008, we applied SFAS No. 157 for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. Upon applying SFAS No. 157, we changed our valuation methodology to consider our nonperformance risk in estimating the fair value of our liabilities. The initial adoption of SFAS No. 157 had no material impact on our Consolidated Financial Statements. In February 2008, the FASB issued FSP FAS 157-2, permitting entities to delay application of SFAS No. 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, we will apply SFAS No. 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed at fair value on a recurring basis. SFAS No. 157 requires two distinct transition approaches: (1) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (2) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable, for all other instruments. Upon adopting SFAS No. 157, we applied a prospective transition as we did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair value is the price that would be 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 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.

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives 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 in active markets for identical assets or liabilities 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, including certain instruments that were part of sales transactions in 2007 and remain to be assigned to the purchaser. These unassigned instruments are entirely offset by reciprocal positions entered into directly with the purchaser. These reciprocal positions have also been included in Level 1.

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 and swaps.

Level 3 Includes 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. Instruments in this category primarily include OTC options.

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 WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth by level within the fair value hierarchy our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements at December 31, 2008 Using:

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(Millions)			
Assets:				
Energy derivatives	$ 680	$ 1,223	$ 547	$ 2,450
Other assets	13		7	20
Total assets	$ 693	$ 1,223	$ 554	$ 2,470
Liabilities:				
Energy derivatives	$ 615	$ 1,313	$ 40	$ 1,968
Total liabilities	$ 615	$ 1,313	$ 40	$ 1,968

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures 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 also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities.

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 short with 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 by management.

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 fair value of options is estimated using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas other model inputs, such as implied volatility by location, is unobservable and requires judgment in estimating. The instruments

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

included in Level 3 at December 31, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled.

The following table sets forth 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, 2008

	Net Derivatives	Other Assets
	(Millions)	
Balance as of January 1, 2008	$ (14)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	88	(3)
Included in *other comprehensive income*	486	
Purchases, issuances, and settlements	(51)	
Transfers into Level 3	3	
Transfers out of Level 3	(5)	
Balance as of December 31, 2008	$ 507	$ 7
Unrealized gains (losses) included in *income from continuing operations* relating to instruments still held at December 31, 2008	$	$

Realized and unrealized gains (losses) included in *income from continuing operations* for the above period 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.

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 balance sheet approximate fair value due to the short-term maturity of these instruments.

Notes and other noncurrent receivables, margin deposits, and customer margin deposits payable: The carrying amounts reported in the balance sheet approximate fair value as these instruments have interest rates approximating market.

Cost-based investments and other securities: This includes cost-based investments, auction rate securities, ARO Trust investments and held-to-maturity securities. These are carried at fair value with the exception of certain international investments that are not publicly traded. In 2007, auction rate securities and held-to-maturity securities are reported in *other current assets and deferred charges* in the Consolidated Balance Sheet. In 2008, auction rate securities are classified within *investments* in the Consolidated Balance Sheet due to auction failures. The ARO Trust investments are classified as available-for-sale and are reported in *other assets and deferred charges* in the Consolidated Balance Sheet. (See Note 9.)

Long-term debt: 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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

similar terms and credit ratings. At December 31, 2008 and 2007, approximately 95 percent and 90 percent, respectively, of our long-term debt was publicly traded.

Guarantees: The *guarantees* represented in the table below 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.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. See Note 14 for discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

Asset (Liability)	2008 Carrying Amount	2008 Fair Value	2007 Carrying Amount	2007 Fair Value
	(Millions)			
Cash and cash equivalents	$ 1,439	$ 1,439	$ 1,699	$ 1,699
Restricted cash (current and noncurrent)	133	133	127	127
Cost-based investments and other securities	37	20(a)	45	20(a)
Notes and other noncurrent receivables	2	2	4	4
Margin deposits	8	8	76	76
Long-term debt, including current portion(b)	(7,874)	(6,285)	(7,890)	(8,729)
Guarantees	(38)	(32)	(40)	(34)
Customer margin deposits payable	(30)	(30)	(10)	(10)
Net energy derivatives(c):				
Energy commodity cash flow hedges	458	458	(268)	(268)
Other energy derivatives	24	24	(100)	(100)

(a) Excludes certain international investments in companies that are not publicly traded and therefore it is not practicable to estimate fair value. (See Note 3.)

(b) Excludes capital leases. (See Note 11.)

(c) A portion of these derivatives is included in assets and liabilities of discontinued operations. (See Note 2.)

Energy Derivatives

Our energy derivative contracts include the following:

Futures contracts: Futures contracts are standardized commitments through an organized commodity exchange to either purchase or sell a commodity at a future date for a specified price. Futures are generally settled in cash, but may be settled through delivery of the underlying commodity. The fair value of these contacts is generally determined using quoted prices.

Forward contracts: Forward contracts are over-the-counter commitments to either purchase or sell a commodity at a future date for a specified price, which involve physical delivery of energy commodities, and may contain either fixed or variable pricing terms. Forward contracts are generally valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Swap agreements: Swap agreements require us to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or between variable prices of energy commodities at different locations. Swap agreements are generally valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Option contracts: Physical and financial option contracts give the buyer the right to exercise the option and receive the difference between a predetermined strike price and a market price at the date of exercise. An option to purchase and an option to sell can be combined in an instrument called a collar to set a minimum and maximum transaction price. These contracts are generally valued based on option pricing models considering prices of the underlying energy commodities over the contract life, volatility of the commodity prices, contractual volumes, estimated volumes under option and other arrangements, and a risk-free market interest rate.

Energy commodity cash flow hedges

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and forecasted sales of NGLs attributable to commodity price risk. Certain of these derivatives have been designated as cash flow hedges under SFAS No. 133.

Our Exploration & Production segment 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 Midstream segment produces, buys and sells NGLs at different locations throughout the United States. Our Midstream segment also buys the required fuel and shrink needed to generate NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices, we may hedge price risk by entering into NGL swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of 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. Midstream does not have any commodity-related cash flow hedges at December 31, 2008.

Changes in the fair value of our cash flow hedges are deferred in other comprehensive income and are reclassified into *revenues* 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. During 2008, we reclassified approximately $2 million of net losses from other comprehensive income to earnings as a result of the discontinuance of cash flow hedges because the forecasted transaction did not occur by the end of the originally specified time period. In second-quarter 2007, we recognized a net gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains of our former power business from *accumulated other comprehensive income/loss* to earnings. This reclassification was based on the determination that the hedged forecasted transactions were probable of not occurring. See Note 2 for further discussion. Approximately $2 million and $14 million of net losses from hedge ineffectiveness are included in *revenues* during 2008 and 2007, respectively. For 2008 and 2007, there are no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2008, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to four years. Based on recorded values at December 31, 2008, approximately $189 million of net gains (net of income

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

tax provision of $115 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, 2008. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2009 will likely differ from these values. These gains or losses will offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Other energy derivatives

Our Gas Marketing Services and Exploration & Production segments have other energy derivatives that have not been designated or do not qualify as SFAS No. 133 hedges. As such, the net change in their fair value is recognized in *revenues* in the Consolidated Statement of Income. Even though they do not qualify for hedge accounting (see *derivative instruments and hedging activities* in Note 1 for a description of hedge accounting), certain of these derivatives hedge our future cash flows on an economic basis.

Other energy-related contracts

We also hold significant nonderivative energy-related contracts, such as storage and transportation agreements, in our Gas Marketing Services portfolio. These have not been included in the financial instruments table above or in our Consolidated Balance Sheet because they are not derivatives as defined by SFAS No. 133.

Guarantees

In addition to the guarantees and payment obligations discussed elsewhere in these footnotes (see Notes 3 and 16), we have issued guarantees and other similar arrangements as discussed below.

In connection with agreements executed to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers that may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to exceed the minimum purchase price.

We are required by certain lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any taxes required to be paid by the lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. 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.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 $42 million at December 31, 2008, and $44 million at December 31, 2007. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $38 million at December 31, 2008.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third-party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

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 at December 31, 2008 and 2007:

	2008	**2007**
	(Millions)	
Receivables by product or service:		
Sale of natural gas and related products and services	$ 653	$ 882
Transportation of natural gas and related products	158	177
Joint interest	86	80
Sales of power and related services		55
Other	49	53

Total	$ 946	$ 1,247

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, Venezuela and Canada. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

Our Venezuelan operations are operated for the exclusive benefit of PDVSA. As energy commodity prices have sharply declined, PDVSA has failed to make regular payments to many service providers, including us. Included within *sale of natural gas and related products and services* in the table above at December 31, 2008, is a $57 million net receivable from PDVSA, none of which was 60 days old or older at that date. We continue to

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

monitor the situation and are actively seeking resolution with PDVSA. The collection of receivables from PDVSA has historically been slower and more time consuming than our other customers due to their policies and the political unrest in Venezuela. We expect, at this time, that the amounts will ultimately be paid.

Derivative assets and liabilities

We have a risk of loss as a result of 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 results from items including credit considerations and the regulatory environment for 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. Additional 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 2008 and 2007, we did not incur any significant losses due to counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 2), as of December 31, 2008, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders	127	896
Financial institutions	1,558	1,559
	$ 1,687	2,457
Credit reserves		(6)
Gross credit exposure from derivatives		$ 2,451

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, 2008, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total

		(Millions)		
Gas and electric utilities	$		$	1
Energy marketers and traders		79		80
Financial institutions		600		600
	$	679		681
Credit reserves				(6)
Net credit exposure from derivatives			$	675

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s of BBB- or Moody s Investors Service rating of Baa3 in investment grade.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our ten largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are five counterparty positions, representing 72 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 with 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 changes in the credit rating of the counterparty financial institution.

At December 31, 2008, the designated collateral agent held $198 million of collateral support on our behalf under Exploration & Production s hedging facility. In addition, we held collateral support, including letters of credit, of $36 million related to our other derivative positions.

Revenues

In 2008, 2007 and 2006, 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.

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 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 we anticipate will satisfy 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 approximately $24 million at December 31, 2008. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us. 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.

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:

State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use.

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.

A Missouri class action and the cases from other jurisdictions were transferred to the federal court in Nevada. 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.

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.

On January 13, 2009, the Missouri state court dismissed a case for lack of standing. We expect that the decision will be appealed.

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, 2008, 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 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

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 remediation activities at certain sites to comply with Washington s current environmental standards. At December 31, 2008, we have accrued liabilities of $9 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. The new standard 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 the new 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, 2008, we have accrued liabilities totaling $6 million for these costs.

In April 2007, the New Mexico Environment Department s Air Quality Bureau (NMED) issued an 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.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as 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, 2008, we have accrued liabilities of $9 million for such excess costs.

Other

At December 31, 2008, we have accrued environmental liabilities of $14 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;

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Discontinued petroleum refining facilities; and

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 have opposed class certification and a hearing on plaintiffs second motion to certify the class was held in April 2005. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Grynberg

In 1998, the U.S. Department of Justice (DOJ) informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys fees, and costs. In connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. The District Court dismissed all claims against us and our wholly owned subsidiaries. The matter is on appeal to the Tenth Circuit Court of Appeals.

In August 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in state court in Denver, Colorado. The plaintiffs alleged we used mismeasurement techniques that distorted the British Thermal Unit heating content of natural gas resulting in the underpayment of royalties to them and other independent natural gas producers. They also alleged we took inappropriate deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, they were seeking actual damages between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1 million. In 2005, the parties agreed to dismiss mismeasurement claims. In September

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008, the court ruled in our favor on motions for summary judgment dismissing various claims. Trial on the remaining breach of contract and accounting claims occurred in November 2008. The jury found against us and awarded less than $2 million, which we believe materially concludes the matter. The plaintiffs seek to increase the total award by approximately $1 million, which we have contested.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously a subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the price of WilTel securities. WilTel was dismissed as a defendant as a result of its bankruptcy.

On July 6, 2007, the court granted various defendants motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. On February 18, 2009, the Tenth Circuit Court of Appeals affirmed the lower court s decision. The plaintiffs might seek rehearing before the Tenth Circuit or request a writ of certiorari from the United States Supreme Court. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court s judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), has been engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when WAPI sold the Alaska refinery and ceased shipping on the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order, which the RCA adopted. On February 15, 2008, the Alaska Supreme Court upheld the RCA s order and on March 16, 2008, the D.C. Circuit Court of Appeals upheld the FERC s order. We have paid substantially all amounts invoiced by the Quality Bank Administrator and third parties, except certain disputed amounts which remain accrued.

In 2008, we concluded that the likelihood of successful appeal by the counterparties was remote, and we reduced remaining amounts accrued in excess of our estimated remaining obligation by $54 million. On January 12, 2009, this matter concluded when the U.S. Supreme Court denied a counterparty s request for a writ of certiorari to appeal the ruling of the D.C. Circuit Court of Appeals.

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

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. 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. In December 2008, the Wyoming Supreme Court ruled against us. The negative assessment for the 2000-2002 time period resulted in additional severance and ad valorem taxes of $4 million. We have accrued a total liability of $39 million related to this matter representing our exposure, including interest, through the end of 2008. We have petitioned for rehearing of a portion of the ruling.

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. The parties have reached a partial settlement agreement for an amount that was previously accrued. The partial settlement has received preliminary approval by the court, and we anticipate trial in late 2009 on remaining issues related to royalty payment calculation and obligations under specific lease provisions. We are not able to estimate the amount of any additional exposure at this time.

Certain other royalty matters are currently being litigated by other producers with a federal regulatory agency in Colorado and with a state agency in New Mexico. Although we are not a party to these matters, the final outcome of those cases might lead to a future unfavorable impact on our results of operations.

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, 2008, 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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 financial position.

Commitments

Commitments for construction and acquisition of property, plant and equipment are approximately $472 million at December 31, 2008.

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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	Minimum Pension Liability	Prior Service Cost	Net Actuarial Gain (Loss)	Prior Service Cost	Net Actuarial Gain (Loss)	Total
	(Millions)							
Balance at December 31, 2005	$ (374)	$ 80	$ (4)	$	$	$	$	$ (298)
2006 Change:								
Pre-income tax amount	423	(4)	(1)					418
Income tax provision	(162)							(162)
Net reclassification into earnings of derivative instrument losses (net of a $82 million income tax benefit)	133							133
	394	(4)	(1)					389
Adjustment to initially apply SFAS No. 158:								
Pre-income tax amount			8	(6)	(243)*	(7)	(8)	(256)
Income tax (provision) benefit			(3)	2	93	3	10	105
			5	(4)	(150)	(4)	2	(151)
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 minority interest	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 minority interest	(2)				7			5
Balance at December 31, 2008	$ 296	$ 53	$	$ (3)	$ (434)	$ 6	$ 2	$ (80)

* Includes $1 million for the Net Actuarial Loss of an equity method investee.

** Includes a $429 million reclassification into earnings of deferred net hedge gains related to the sale of our power business. (See Note 2.)

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 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 Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services 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 include third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following geographic area data includes *revenues from external customers* based on product shipment origin and *long-lived assets* based upon physical location.

	Other	**Total**

	United States		
		(Millions)	
Revenues from external customers:			
2008	$ 11,924	$ 428	$ 12,352
2007	10,065	421	10,486
2006	8,905	394	9,299
Long-lived assets:			
2008	$ 18,419	$ 659	$ 19,078
2007	16,279	713	16,992
2006	14,487	682	15,169

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our foreign operations are primarily located in Venezuela, Canada, and Argentina. *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 & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
2008							
Segment revenues:							
External	$ (215)	$ 1,600	$ 5,586	$ 5,371	$ 10	$	$ 12,352
Internal	3,336	34	56	1,041	14	(4,481)	
Total revenues	$ 3,121	$ 1,634	$ 5,642	$ 6,412	$ 24	$ (4,481)	$ 12,352
Segment profit (loss)	$ 1,260	$ 689	$ 963	$ 3	$ (3)	$	$ 2,912
Less:							
Equity earnings	20	59	58				137
Income from investments			1				1
Segment operating income (loss)	$ 1,240	$ 630	$ 904	$ 3	$ (3)	$	2,774
General corporate expenses							(149)
Total operating income							$ 2,625
Other financial information:							
Additions to long-lived assets	$ 2,563	$ 413	$ 679	$	$ 42	$	$ 3,697
Depreciation, depletion & amortization	$ 737	$ 321	$ 233	$ 1	$ 18	$	$ 1,310
2007							
Segment revenues:							
External	$ (167)	$ 1,576	$ 5,142	$ 3,924	$ 11	$	$ 10,486
Internal	2,188	34	38	709	15	(2,984)	
Total revenues	$ 2,021	$ 1,610	$ 5,180	$ 4,633	$ 26	$ (2,984)	$ 10,486

Segment profit (loss)	$	756	$	673	$	1,072	$	(337)	$	(1)	$		$	2,163
Less equity earnings		25		51		61								137
Segment operating income (loss)	$	731	$	622	$	1,011	$	(337)	$	(1)	$			2,026
General corporate expenses														(161)
Total operating income													$	1,865
Other financial information:														
Additions to long-lived assets	$	1,717	$	546	$	610	$		$	27	$		$	2,900
Depreciation, depletion & amortization	$	535	$	315	$	214	$	7	$	10	$		$	1,081
2006														
Segment revenues:														
External	$	(266)	$	1,336	$	4,094	$	4,128	$	7	$		$	9,299
Internal		1,677		12		65		921		20		(2,695)		
Total revenues	$	1,411	$	1,348	$	4,159	$	5,049	$	27	$	(2,695)	$	9,299
Segment profit (loss)	$	552	$	467	$	675	$	(195)	$	(13)	$		$	1,486
Less equity earnings		22		37		40								99
Segment operating income (loss)	$	530	$	430	$	635	$	(195)	$	(13)	$			1,387
General corporate expenses														(132)
Securities litigation settlement and related costs														(167)
Total operating income													$	1,088
Other financial information:														
Additions to long-lived assets	$	1,496	$	913	$	279	$	1	$	18	$		$	2,707
Depreciation, depletion & amortization	$	360	$	282	$	203	$	7	$	11	$		$	863

Table of Contents

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table reflects *total assets* and *equity method investments* by reporting segment.

	Total Assets			Equity Method Investments		
	December 31, 2008	December 31, 2007	December 31, 2006	December 31, 2008	December 31, 2007	December 31, 2006
	(Millions)					
Exploration & Production(1)	$ 10,286	$ 8,692	$ 7,851	$ 87	$ 72	$ 59
Gas Pipeline	9,149	8,624	8,332	570	483	432
Midstream Gas & Liquids	7,024	6,604	5,562	290	321	323
Gas Marketing Services(2)	3,064	4,437	5,519			
Other	3,532	3,592	3,923			
Eliminations	(7,055)	(7,073)	(7,187)			
	26,000	24,876	24,000	947	876	814
Discontinued operations	6	185	1,402			
Total	$ 26,006	$ 25,061	$ 25,402	$ 947	$ 876	$ 814

(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 2008 and 2007 is due primarily 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.

Table of Contents

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
2008				
Revenues	$ 3,204	$ 3,701	$ 3,245	$ 2,202
Costs and operating expenses	2,353	2,719	2,364	1,720
Income from continuing operations	416	419	369	130
Net income	500	437	366	115
Basic earnings per common share:				
Income from continuing operations	.71	.72	.63	.23
Diluted earnings per common share:				
Income from continuing operations	.70	.70	.62	.23
2007				
Revenues	$ 2,348	$ 2,805	$ 2,844	$ 2,489
Costs and operating expenses	1,823	2,161	2,206	1,817
Income from continuing operations	170	243	228	206
Net income	134	433	198	225
Basic earnings per common share:				
Income from continuing operations	.28	.40	.38	.35
Diluted earnings per common share:				
Income from continuing operations	.28	.40	.38	.34

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.

Prior period amounts reported above have been adjusted to reflect the presentation of certain revenues and costs for Exploration & Production on a net basis. These adjustments reduced *revenues* and reduced *costs and operating expenses* by the same amount, with no net impact on segment profit. The reductions were as follows (in millions):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2008	$ 20	$ 28	$ 22	$ 10
2007	$ 20	$ 19	$ 16	$ 17

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 of Notes to Consolidated Financial Statements);

$43 million of income including associated interest related to the partial settlement of the Gulf Liquids litigation at Midstream (see Notes 4 and 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).

Table of Contents

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA (Continued)
(Unaudited)

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).

Net income for fourth-quarter 2007 includes a $23 million adjustment to increase the tax provision relating to an income tax contingency and the following pre-tax items:

$156 million mark-to-market loss recognized at Gas Marketing Services on a legacy derivative natural gas sales contract that we expect to assign to another party in 2008 under an asset transfer agreement that we executed in December 2007;

$20 million accrual for litigation contingencies at Gas Marketing Services (see Note 4);

$19 million in premiums, fees and expenses related to early debt retirement;

$12 million of income related to a favorable litigation outcome at Midstream (see Note 4);

$10 million charge related to an impairment of the Carbonate Trend pipeline at Midstream (see Note 4);

$9 million charge related to the reserve for certain international receivables at Midstream;

$6 million net loss, including transaction expenses, related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2).

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA (Continued)
(Unaudited)

Net income for third-quarter 2007 includes the following pre-tax items:

$17 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);

$12 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral (see Note 4).

Net income for second-quarter 2007 includes the following pre-tax items:

$429 million gain associated with the reclassification of deferred net hedge gains to earnings related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);

$111 million impairment of the carrying value of certain derivative contracts related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);

$17 million of income associated with a change in estimate related to a regulatory liability at Northwest Pipeline (see Note 4);

$15 million impairment of our Hazelton facility included in discontinued operations (see summarized results of discontinued operations at Note 2);

$14 million of gains from the sales of cost-based investments (see Note 3);

$14 million of expenses related to the sale of our discontinued power business (see summarized results of discontinued operations at Note 2);

$6 million of income associated with the payments received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral (see Note 4).

Net income for the first-quarter 2007 includes the following pre-tax items:

$8 million of income due to the reversal of a planned major maintenance accrual at Midstream.

Table of Contents

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(Unaudited)

The following information pertains to our oil and gas producing activities and is presented in accordance with SFAS No. 69, Disclosures About Oil and Gas Producing Activities. The information is required to be disclosed by geographic region. 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. However, proved reserves and revenues related to international activities are approximately 3.6 percent and 2.3 percent, respectively, of our total international and domestic proved reserves and revenues. The following information relates only to the oil and gas activities in the United States.

Capitalized Costs

	As of December 31, 2008	2007
	(Millions)	
Proved properties	$ 8,099	$ 6,409
Unproved properties	806	542
	8,905	6,951
Accumulated depreciation, depletion and amortization and valuation provisions	(2,353)	(1,754)
Net capitalized costs	$ 6,552	$ 5,197

Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $726 million and $505 million, net, for 2008 and 2007, respectively. The capitalized cost amounts for 2008 and 2007 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 acreage related to probable/possible reserves acquired through transactions in 2001 and 2008.

Costs Incurred

	For the Year Ended December 31, 2008	2007	2006
		(Millions)	
Acquisition	$ 543	$ 82	$ 84

Exploration	38	38	20
Development	1,699	1,374	1,173
	$ 2,280	$ 1,494	$ 1,277

Costs incurred include capitalized and expensed items.

Acquisition costs are as follows: 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 are $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. The 2006 cost is primarily for additional leasehold and reserve acquisitions in the Fort Worth basin.

Table of Contents

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)
(Unaudited)

Exploration costs 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.

Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip development wells.

Results of Operations

	For the Year Ended December 31,		
	2008	2007	2006
		(Millions)	
Revenues:			
Oil and gas revenues	$ 2,644	$ 1,725	$ 1,238
Other revenues	405	232	109
Total revenues	3,049	1,957	1,347
Costs:			
Production costs	555	360	309
General & administrative	169	144	111
Exploration expenses	27	21	18
Depreciation, depletion & amortization	724	523	351
(Gains)/Losses on sales of interests in oil and gas properties	1	(1)	
Impairment of certain natural gas properties in the Arkoma basin	143		
Other expenses	349	198	59
Total costs	1,968	1,245	848
Results of operations	1,081	712	499
Provision for income taxes	(406)	(273)	(174)
Exploration and production net income	$ 675	$ 439	$ 325

Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit and excludes the $148 million gain on sale of a contractual right to a production payment on certain future international hydrocarbon production.

Prior period amounts have been adjusted to reflect the presentation of certain revenues and costs on a net basis. These adjustments reduced other revenues and reduced other expenses by the same amount, with no net impact on segment profit. The reductions were $72 million in 2007 and $77 million in 2006.

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.

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)
(Unaudited)

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.

Proved Reserves

	2008	2007 (Bcfe)	2006
Proved reserves at beginning of period	4,143	3,701	3,382
Revisions	(220)	(106)	(113)
Purchases	31	19	41
Extensions and discoveries	791	863	669
Wellhead production	(406)	(334)	(277)
Sale of minerals in place			(1)
Proved reserves at end of period	4,339	4,143	3,701
Proved developed reserves at end of period	2,456	2,252	1,945

The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Our 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 limited to those drilling units offsetting productive units that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

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 prior year.

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 and the year-end prices and costs. The average year-end natural gas prices used in the following estimates were $4.41, $5.78, and $4.81 per MMcfe at December 31, 2008, 2007, and 2006, respectively. Future income tax expenses have been computed considering available carry forwards and credits and the appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by SFAS No. 69. Continuation of year-end economic conditions also is assumed. The calculation is

Table of Contents

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)
(Unaudited)

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 $3,772 million of future development costs, approximately 72 percent is estimated to be spent in 2009, 2010 and 2011.

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, 2008	2007
	(Millions)	
Future cash inflows	$ 19,127	$ 23,937
Less:		
Future production costs	5,516	5,345
Future development costs	3,772	3,497
Future income tax provisions	3,284	5,416
Future net cash flows	6,555	9,679
Less 10 percent annual discount for estimated timing of cash flows	3,382	4,876
Standardized measure of discounted future net cash flows	$ 3,173	$ 4,803

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	2008	2007	2006
		(Millions)	
Standardized measure of discounted future net cash flows beginning of period	$ 4,803	$ 2,856	$ 5,281
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(2,091)	(1,426)	(1,179)
Net change in prices and production costs	(2,548)	2,019	(4,052)
Extensions, discoveries and improved recovery, less estimated future costs	1,423	2,163	647
Development costs incurred during year	817	738	881

Changes in estimated future development costs	(724)	(931)	(1,022)
Purchase of reserves in place, less estimated future costs	55	48	63
Sales of reserves in place, less estimated future costs			(2)
Revisions of previous quantity estimates	(395)	(266)	(140)
Accretion of discount	714	434	790
Net change in income taxes	1,108	(1,108)	1,468
Other	11	276	121
Net changes	(1,630)	1,947	(2,425)
Standardized measure of discounted future net cash flows end of period	$ 3,173	$ 4,803	$ 2,856

Table of Contents

THE WILLIAMS COMPANIES, INC.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS Charged to Cost and Expenses	Other (Millions)	Deductions	Ending Balance
Year ended December 31, 2008:					
Allowance for doubtful accounts accounts and notes receivable(a)	$ 27	$ 15	$	$ 2(d)	$ 40
Deferred tax asset valuation allowance(a)	57	(9)		33(d)	15
Price-risk management credit reserves assets(a)	1	1(e)	4(g)		6
Price-risk management credit reserves liabilities(b)		(16)(e)	1(g)		(15)
Year ended December 31, 2007:					
Allowance for doubtful accounts accounts and notes receivable(a)	15	12			27
Deferred tax asset valuation allowance(a)	36	21			57
Price-risk management credit reserves assets(a)	7	(6)(e)			1
Processing plant major maintenance accrual	8			8(c)	
Year ended December 31, 2006:					
Allowance for doubtful accounts accounts and notes receivable(a)	86	4	(66)(f)	9(d)	15
Deferred tax asset valuation allowance(a)	37	(1)			36
Price-risk management credit reserves assets(a)	15	(8)(e)			7
Processing plant major maintenance accrual(h)	7	2		1	8

(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) During 2006, $66 million in previously reserved Enron receivables were sold.

(g) Included in *accumulated other comprehensive loss*.

(h) Included in *accrued liabilities* in 2006.

Table of Contents

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 2008 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 21, 2009 (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 Compliance with Section 16(a) of the Securities Exchange Act of 1934 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 that applies to our Chief Executive Officer, Chief Financial Officer, and Controller, or persons performing similar functions. The Code of Ethics, 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.

Table of Contents

Item 14. *Principal Accountant Fees and Services*

The information regarding our principal accountant fees and services required by Item 9(e) of Schedule 14A will be presented under the heading Principal Accountant 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 March 11, 2005 as Exhibit 3.1 to The Williams Companies, Inc. s Form 10-K) 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	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001 as Exhibit 4(j) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.

4.3	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.
4.4	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.

Exhibit No.	Description
4.5	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed on October 18, 1995 as Exhibit 4.1 to Williams Holdings of Delaware, Inc. s Form 10-Q) and incorporated herein by reference.
4.6	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed on March 28, 2000 as Exhibit 4(o) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.
4.7	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.
4.8	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.
4.9	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.
4.10	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.
4.11	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.
4.12	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.
4.13	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.
4.14	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.
4.15	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.
4.16	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.
4.17	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.

4.18	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.

Exhibit No.	Description
4.19	Registration Rights Agreement, dated as of April 5, 2007, among Northwest Pipeline Corporation and Greenwich Capital Markets, Inc. and Banc of America Securities LLC, acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed on April 6, 2007 as Exhibit 10.1 to Northwest Pipeline Corporation s Form 8-K) and incorporated herein by reference.
4.20	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.
4.21	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.
4.22	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.
4.23	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on September 8, 1997 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 December 17, 2004 between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on December 21, 2004 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K) and incorporated herein by reference.
4.27	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.
4.28	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.
4.29	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.
4.30	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.
4.31	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.
10.1*	

	The Williams Companies Amended and Restated Retirement Restoration Plan effective January 1, 2008.
10.2	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed on March 27, 1996 as Exhibit 10(iii)(g) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.

Exhibit No.	Description
10.3	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.
10.4	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.
10.5	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.
10.6	Form of 2008 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.7	Form of 2008 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.2 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.8	Form of 2008 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.9*	Form of 2008 Restricted Stock Unit Agreement among Williams and non-management directors.
10.10	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.
10.11*	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan.
10.12*	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan.
10.13	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.
10.14*	Amendment No. 1 to The Williams Companies, Inc. 2007 Incentive Plan.
10.15	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.
10.16*	Amendment No. 1 to The Williams Companies, Inc. Employee Stock Purchase Plan.
10.17*	Amendment No. 2 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.
10.19*	The Williams Companies, Inc. Severance Pay Plan.
10.20*	Confidential Separation Agreement and Release between The Williams Companies, Inc. and Michael P. Johnson dated April 2, 2008 (filed on May 1, 2008 as Exhibit 10.4 to The Williams Companies, Inc. s Form 10-Q) and incorporated herein by reference.
10.21	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.
10.22	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.
10.23	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.

Exhibit No.	Description
10.24	U.S. $400,000,000 Five Year Credit Agreement dated January 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 January 26, 2005 as Exhibit 10.3 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.25	U.S. $100,000,000 Five Year Credit Agreement dated January 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 January 26, 2005 as Exhibit 10.4 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.26	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.
10.27	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.
10.28	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.
10.29	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.
10.30	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.
10.31	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.
10.32	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.
10.33	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.
10.34	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.
12*	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14	Code of Ethics (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.

Exhibit No.	Description
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.

* Filed herewith

Table of Contents

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 24, 2009

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 24, 2009
/s/ Donald R. Chappel Donald R. Chappel	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2009
/s/ Ted T. Timmermans Ted T. Timmermans	Controller (Principal Accounting Officer)	February 24, 2009
/s/ Joseph R. Cleveland* Joseph R. Cleveland*	Director	February 24, 2009
/s/ Kathleen B. Cooper* Kathleen B. Cooper*	Director	February 24, 2009
/s/ Irl F. Engelhardt* Irl F. Engelhardt*	Director	February 24, 2009
/s/ William R. Granberry* William R. Granberry*	Director	February 24, 2009

/s/ William E. Green*	Director	February 24, 2009
William E. Green*		
/s/ Juanita H. Hinshaw*	Director	February 24, 2009
Juanita H. Hinshaw*		
/s/ W.R. Howell*	Director	February 24, 2009
W.R. Howell*		

Table of Contents

Signature	Title	Date
/s/ Charles M. Lillis*	Director	February 24, 2009
Charles M. Lillis*		
/s/ George A. Lorch*	Director	February 24, 2009
George A. Lorch*		
/s/ William G. Lowrie*	Director	February 24, 2009
William G. Lowrie*		
/s/ Frank T. MacInnis*	Director	February 24, 2009
Frank T. MacInnis*		
/s/ Janice D. Stoney*	Director	February 24, 2009
Janice D. Stoney*		

*By: /s/ La Fleur C. Browne — February 24, 2009

La Fleur C. Browne
Attorney-in-Fact

INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Restated Certificate of Incorporation, as supplemented (filed on March 11, 2005 as Exhibit 3.1 to The Williams Companies, Inc. s Form 10-K) 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	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed on March 12, 2001 as Exhibit 4(j) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.
4.3	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.
4.4	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.
4.5	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed on October 18, 1995 as Exhibit 4.1 to Williams Holdings of Delaware, Inc. s Form 10-Q) and incorporated herein by reference.
4.6	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Citibank, N.A., as Trustee (filed on March 28, 2000 as Exhibit 4(o) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.
4.7	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.
4.8	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.
4.9	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.
4.10	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.
4.11	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.
4.12	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.
4.13	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.
4.14	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.

Exhibit No.	Description
4.15	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.
4.16	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.
4.17	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.
4.18	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.
4.19	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.
4.20	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.
4.21	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.
4.22	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on September 8, 1997 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3) and incorporated herein by reference.
4.23	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.
4.24	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.
4.25	Indenture dated December 17, 2004 between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee (filed on December 21, 2004 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K) 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.

Exhibit No.	Description
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.
10.1*	The Williams Companies Amended and Restated Retirement Restoration Plan effective January 1, 2008.
10.2	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed on March 27, 1996 as Exhibit 10(iii)(g) to The Williams Companies, Inc. s Form 10-K) and incorporated herein by reference.
10.3	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.
10.4	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.
10.5	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.
10.6	Form of 2008 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.7	Form of 2008 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.2 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.8	Form of 2008 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed on February 29, 2008 as Exhibit 99.1 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.9*	Form of 2008 Restricted Stock Unit Agreement among Williams and non-management directors.
10.10	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.
10.11*	Amendment No. 1 to The Williams Companies, Inc. 2002 Incentive Plan.
10.12*	Amendment No. 2 to The Williams Companies, Inc. 2002 Incentive Plan.
10.13	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.
10.14*	Amendment No. 1 to The Williams Companies, Inc. 2007 Incentive Plan.
10.15	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.
10.16*	Amendment No. 1 to The Williams Companies, Inc. Employee Stock Purchase Plan.
10.17*	Amendment No. 2 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.
10.19*	The Williams Companies, Inc. Severance Pay Plan.
10.20*	Confidential Separation Agreement and Release between The Williams Companies, Inc. and Michael P. Johnson dated April 2, 2008 (filed on May 1, 2008 as Exhibit 10.4 to The Williams Companies, Inc. s Form 10-Q) and incorporated herein by reference.
10.21	

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
10.22	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.
10.23	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.
10.24	U.S. $400,000,000 Five Year Credit Agreement dated January 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 January 26, 2005 as Exhibit 10.3 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.25	U.S. $100,000,000 Five Year Credit Agreement dated January 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 January 26, 2005 as Exhibit 10.4 to The Williams Companies, Inc. s Form 8-K) and incorporated herein by reference.
10.26	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.
10.27	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.
10.28	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.
10.29	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.
10.30	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.
10.31	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.
10.32	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.
10.33	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.

Table of Contents

Exhibit No.	Description
10.34	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.
12*	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14	Code of Ethics (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.

* Filed herewith