UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number 1-4174

The Williams Companies, Inc.

(Exact name of Registrant as Specified in Its Charter)

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

918-573-2000
(Registrant's Telephone Number, Including Area Code)

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

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

Securities registered pursuant to Section 12(g) of the Act:
5.50% Junior Subordinated Convertible Debentures due 2033

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

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

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

Indicate by check mark 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. ☒

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

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

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

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

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.

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	2006
		(Bcfe)	
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

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 (In trillion British Thermal Units)	2006
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.

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 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.

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," "scheduled" or similar 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;

- 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.

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:

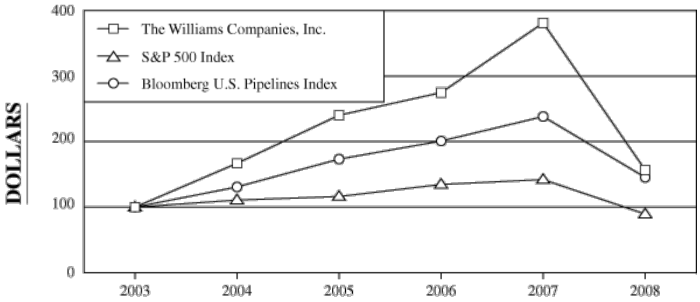
	2008			2007		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$ 36.99	$ 30.96	$ .10	$ 28.94	$ 25.32	$ .09
2nd	$ 40.31	$ 33.65	$ .11	$ 32.43	$ 28.20	$ .10
3rd	$ 39.90	$ 21.85	$ .11	$ 34.72	$ 30.08	$ .10
4th	$ 22.50	$ 12.13	$ .11	$ 37.16	$ 33.68	$ .10

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.

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

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)."

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.

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.

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.

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* *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 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.

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.

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	2006
		(Millions)	
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.

Midstream Gas & Liquids

Overview of 2008

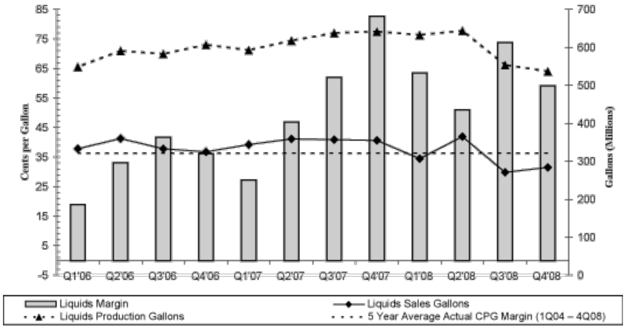
Midstream's ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers.

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.

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 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.

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.

Contractual Obligations

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

	2009	2010-2011	2012-2013	Thereafter	Total
			(Millions)		
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.

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.

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.

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.

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

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

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.

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:		
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)	613	608
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.

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 (Note 12)	2	25	—	—	—	—	27
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.

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 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.

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*.

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.

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*.

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 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 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.

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 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 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.

Summarized Results of Discontinued Operations

	2008	2007	2006
		(Millions)	
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.

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.

Investments

	December 31, 2008	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.

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.)

Note 5. Provision for Income Taxes

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

	2008	2007	2006
		(Millions)	
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	2006
		(Millions)	
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 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.

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)		
Income from continuing operations available to common stockholders for basic and diluted earnings per common share(1)	$ 1,334	$ 847	$ 347
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

(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.

Table of Contents

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

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

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

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.

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 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.

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 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.

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)	December 31, 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 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.

- 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.

Table of Contents

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 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.

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		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life	Options		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life
	(Millions)			(Years)	(Millions)			(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.

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.

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 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 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 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

	2008		2007	
Asset (Liability)	Carrying Amount	Fair Value	Carrying Amount	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.

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 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.

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 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.

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 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 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;

- 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

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 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.

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

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.)

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.

	United States	Other	Total
		(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

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

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.

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).

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.

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	As of December 31, 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.

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 (Millions)	2006
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.

- 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 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

THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS Charged to Cost and Expenses	ADDITIONS Other	Deductions	Ending Balance
			(Millions)		
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.

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.

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.

	Page
Covered by report of independent auditors:	
Consolidated statement of income for each year in the three-year period ended December 31, 2008	81
Consolidated balance sheet at December 31, 2008 and 2007	82
Consolidated statement of stockholders' equity for each year in the three-year period ended December 31, 2008	83
Consolidated statement of cash flows for each year in the three-year period ended December 31, 2008	84
Notes to consolidated financial statements	85
Schedule for each year in the three-year period ended December 31, 2008:	
II — Valuation and qualifying accounts	146
Not covered by report of independent auditors:	
Quarterly financial data (unaudited)	139
Supplemental oil and gas disclosures (unaudited)	142

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

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

Signature	Title	Date
/s/ Charles M. Lillis* Charles M. Lillis*	Director	February 24, 2009
/s/ George A. Lorch* George A. Lorch*	Director	February 24, 2009
/s/ William G. Lowrie* William G. Lowrie*	Director	February 24, 2009
/s/ Frank T. MacInnis* Frank T. MacInnis*	Director	February 24, 2009
/s/ Janice D. Stoney* Janice D. Stoney*	Director	February 24, 2009
*By: /s/ La Fleur C. Browne La Fleur C. Browne *Attorney-in-Fact*		February 24, 2009

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.

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

Exhibit 10.1

**THE WILLIAMS COMPANIES
AMENDED AND RESTATED
RETIREMENT RESTORATION PLAN**

Effective as of January 1, 2008

THE WILLIAMS COMPANIES
AMENDED AND RESTATED
RETIREMENT RESTORATION PLAN

ESTABLISHMENT OF PLAN

WHEREAS, The Williams Companies, Inc. and certain of its subsidiaries ("Employers") maintain The Williams Pension Plan ("Pension Plan") for the benefit of eligible employees of the Employers;

WHEREAS, Sections 401(a)(17) and 415 of the Internal Revenue Code ("Code") establish limitations as to the amount of pension benefit which may be accrued under or payable from the Pension Plan on behalf of any participant therein; and

WHEREAS Code Section 409A imposes new requirements upon distributions from supplemental plans; and

WHEREAS, to reflect the requirements of Code Section 409A, The Williams Companies, Inc. desires to amend and restate The Williams Companies Retirement Restoration Plan, as effective January 1, 2005, a supplemental plan under which the portion of the pension benefit (and related death benefit) of an eligible employee of an Employer which becomes subject to such limitations of the Code shall be payable from general corporate assets.

NOW, THEREFORE, The Williams Companies, Inc. hereby adopts, effective as of January 1, 2008, The Williams Companies Retirement Restoration Plan as amended and restated and set forth hereinafter.

ARTICLE I

Introduction

This document is generally effective as of January 1, 2008 (the “Effective Date”) and amends and restates The Williams Companies Retirement Restoration Plan, as effective January 1, 2005 (the “2005 Document”), with respect to periods commencing on and after the Effective Date. It sets forth the terms of the Plan applicable to deferrals which are subject to Section 409A, *i.e.*, generally, deferred amounts earned or vested after December 31, 2004 (the “409A Program”). Certain other deferrals under the Plan shall be governed by a separate set of documents which set forth the pre-Section 409A terms of the Plan (the “Pre-409A Program”) to the extent such other deferrals and the terms of Pre-409A Program are not incorporated into this document. Together, this document, the 2005 Document and the documents for the Pre-409A Program describe the terms of a single plan. However, amounts subject to the terms of this 409A Program and amounts subject to the terms of the Pre-409A Program shall be tracked separately at all times. The preservation of the terms of the Pre-409A Program, without material modification, and the separation between the 409A Program amounts and the Pre-409A Program amounts are intended to be sufficient to permit the Pre-409A Program to remain exempt from Section 409A. Subject to the applicable Plan termination provisions, with respect to vested benefits under the Pre-409A Program: (i) in the case of vested Participants on December 31, 2004 who were receiving vested benefits on such date, such benefits shall continue to be paid under the Pre-409A Program at the same time and in the same amounts as specified under the form of payment in effect on such date; and (ii) in the case of vested Participants who were not receiving vested benefits on such date, such benefits shall be paid under the Pre-409A Program in a lump sum at the time specified in Article IV of The Williams Companies Supplemental Retirement Plan as in effect on December 31, 2004.

ARTICLE II

Definitions

In this Plan, unless the context clearly implies otherwise, the singular includes the plural, the masculine includes the feminine, and initially capitalized words have the following meaning:

2.1 Actuarial Equivalent. An amount or benefit of equivalent current value to the amount or benefit which would otherwise have been provided to or on account of a Participant or Beneficiary determined on the basis of the actuarial assumptions then in effect under the Pension Plan and such other assumptions permitted by Code Section 409A and final regulations promulgated thereunder as may be deemed necessary by an actuary selected by the Company or the Committee.

2.2 Base Pay. The regular wages and salary of a Participant, which is in excess of Code limitations and which does not include any short term disability paid by an Employer, overriding royalties, amounts paid under a phantom override plan, bonuses (including, but not limited to bonuses under The Williams Companies, Inc. Executive Incentive Compensation Plan), salary reduction amounts contributed to The Williams Investment Plus Plan, salary reduction amounts contributed to any qualified transportation plan established by an Employer in accordance with Code Section 132(f)(7) or to any cafeteria plan or flexible benefits plan established by an Employer in accordance Section 125 and related sections of the Code, severance pay, cost of living pay, housing pay, relocation pay (including mortgage interest differential) or any such other taxable and non-taxable fringe benefits and extraordinary compensation of any kind.

2.3 Basic Supplemental Benefit. The amount payable to a Vested Participant in the form of a lump sum distribution based upon the amount credited to his Supplemental Pension Account pursuant to the applicable provisions of this Plan.

2.4 Beneficiary. The Surviving Spouse or other person who is entitled to receive benefits pursuant to Article V of this Plan.

2.5 Benefit Starting Date. With respect to a Supplemental Retirement Benefit, the date shall be the later of the first day of the month following the date the Participant attains age fifty-five (55) or the first day of the month following the expiration of the six (6) month period commencing with the date the Participant incurs a Separation from Service. With respect to a Death Benefit, the date shall be the first day of the month following the expiration of the three (3) month period commencing with the Participant's date of death. With respect to a Supplemental Disability Benefit, the date shall be the date specified under the provisions of Section 3.5. A benefit payable under the Pre-409A Program, shall be payable as of the date a corresponding benefit is payable under the Pension Plan.

2.6 Board. The Board of Directors of the Company as constituted from time to time.

2.7 Change in Control. The occurrence of (i) a Change in the Ownership of the Company, as defined below, (ii) a Change in Effective Control of the Company, as defined below, or (iii) a Change in the Ownership of a Substantial Portion of the Assets of the Company, as defined below. To qualify as a Change in Control event, the occurrence of the event shall be objectively determinable, strictly ministerial, and shall not involve any discretionary authority by the plan administrator. Code Section 318(a) shall be applied to determine stock ownership for purposes of this section. Substantially vested stock underlying a vested option is considered owned by the person who holds the vested option (and the stock underlying an unvested option is not considered owned by the person who holds an unvested option). To qualify as a Change in Control with respect to a Participant, the Change in Control must relate to (x) the corporation for whom the Participant is performing services at the time of the Change in Control event; (y) the corporation that is liable for the payment of benefits under this Plan (or all corporations which are liable for payment if more than one corporation is liable) but only if either the benefits are attributable to the performance of service by the Participant for such corporation (or corporations) or there is a bona fide business purpose for such corporation (or corporations) to be liable for such payment and, in either case, no significant purpose of making such corporation or corporations liable for such payment is the avoidance of Federal income tax; or (z) a corporation that is a majority shareholder of a corporation identified in subsections (x) or (y) above, or any corporation in a chain of corporations in which each corporation is a majority shareholder of another corporation in the chain, ending in a corporation identified in subsections (x) or (y) above. The provisions of Treas. Reg. § 1.409A-3, as amended, shall govern with respect to the definition of terms used therein and in the interpretation of whether a Change in Control has occurred.

(a) A "Change in the Ownership of the Company" occurs on the date that any one person or more than one person Acting as a Group, as defined below, acquires ownership of Stock of the Company ("Stock") that, together with Stock held by such person or group, constitutes more than fifty percent (50%) of the total fair market value or total voting power of the Stock. However, if any one person or more than one person Acting as a Group, is considered to own more than fifty percent (50%) of the total fair market value or total voting power of the Stock, the acquisition of additional Stock by the same person or persons is not considered to cause a Change in the Ownership of the

Company. An increase in the percentage of Stock owned by any one person, or persons Acting as a Group, as a result of a transaction in which the Company acquires its Stock in exchange for property will be treated as an acquisition of Stock for purposes of this subsection. This subsection applies only when there is a transfer of Stock (or issuance of Stock) and Stock remains outstanding after the transaction.

(b) "Acting as a Group." persons will not be considered to be Acting as a Group solely because they purchase or own Stock at the same time or as a result of the same public offering. However, persons will be considered to be Acting as a Group if they are owners of a corporation that enters into a merger, consolidation, purchase or acquisition of Stock, or similar business transaction with the Company. If a person owns stock in both corporations that enter into a merger, consolidation, purchase or acquisition of Stock or similar transaction involving another corporation, such shareholder is considered to be Acting as a Group with other shareholders only in such corporation prior to the transaction giving rise to the change and not with respect to the ownership interest in the other corporation.

(c) A "Change in the Effective Control of the Company" occurs only on either of the following dates: (1) The date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) ownership of the Stock possessing thirty percent (30%) or more of the total voting power of the Stock of the Company; or (2) The date a majority of members of the Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board before the date of the appointment or election.

If any one person, or more than one person Acting as a Group, is considered to be in effective control of the Company, the acquisition of additional control of the Company by the same person or persons is not considered to cause a Change in the Effective Control of the Company.

(d) A “Change in the Ownership of a Substantial Portion of the Assets of the Company” occurs on the date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) assets from the Company that have a total gross fair market value equal to or more than forty percent (40%) of the total gross fair market value of all assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, the gross fair market value means the value of the assets of the Company or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. Notwithstanding the foregoing, there is no Change in the Ownership of a Substantial Portion of the Assets of the Company when there is a transfer of assets to an entity that is controlled by the shareholders of the Company immediately after the transfer. A transfer of assets by the Company is not treated as a Change in the Ownership of a Substantial Portion of the Assets of the Company if the assets are transferred to (1) a shareholder of the Company (immediately before the asset transfer) in exchange for or with respect to its Stock; (2) an entity, fifty percent (50%) or more of the total value or voting power of which is owned, directly or indirectly, by the Company; (3) a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock; or (4) an entity, at least fifty percent (50%) of the total value or voting power of which is owned, directly or indirectly, by a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock. For purposes of this subsection (d), and except as otherwise provided, a person's status is determined immediately after the transfer of assets.

2.8 Code. The Internal Revenue Code of 1986, as amended.

2.9 Code Limitations. The limitations on compensation which may be taken into account in determining benefits under and on benefits payable from the Pension Plan imposed by Sections 401(a)(17) and 415 of the Code.

2.10 Committee. The Compensation Committee of the Board.

2.11 Company. The Williams Companies, Inc., a Delaware corporation or any successor thereto.

2.12 Credit Date. (a) With respect to Supplemental Compensation Credits, the last day of the applicable Plan Year referenced in the context in which such term is used, and (b) with respect to Supplemental Interest Credits, the last day of each quarter of each Plan Year.

2.13 Death Benefit. The benefit provided under Article V of this Plan to the Surviving Spouse or other Beneficiary of a Participant.

2.14 Disability. A physical or mental condition which satisfies the requirements for disability payments under The Williams Companies, Inc. Long-Term Disability Plan as in effect on January 1, 2008.

2.15 Eligible Employee. Any Employee of an Employer who (a) is a participant in the Pension Plan and (b) holds a position that has been classified as an executive position by the Company's executive compensation department.

2.16 Employee. An “eligible Employee” as such term is defined under the Pension Plan.

2.17 Employer. An “Employer” as such term is defined under the Pension Plan.

2.18 Former Participant. A Participant who has a benefit which becomes payable after December 31, 2007 under either the Pre-409A Program portion or the 409A Program portion of this Plan but who is no longer an Eligible Employee.

2.19 Key Employee. An employee designated on an annual basis by the Company as of December 31 (the “Key Employee Designation Date”) as an employee meeting the requirements of Section 416(i) of Code without regard to paragraph (5) thereof utilizing the definition of compensation under Treasury Regulation § 1.415(c)-2(d)(2). A Participant designated as a “key employee” shall be a “key employee” for the entire twelve (12) month period beginning on April 1 following the Key Employee Designation Date.

2.20 Nonservice Participant. A Vested Participant who is a “Nonservice Participant” as such term is defined under the Pension Plan.

2.21 Normalized Pension Benefit. The pension benefit which would have been paid during a Plan Year to the Participant or his Beneficiary (including a spouse or other contingent annuitant) pursuant to the benefit formula set forth in Section 2.1 of the Pension Plan which is applicable to such Participant and the method of payment selected by the Participant under the Pension Plan, without taking into account the Code Limitations; but (for any Plan Year beginning on or after January 1, 2002) taking into account only the Supplemental Retirement Compensation of the Participant in lieu of “Compensation” under Section 2.19 of the Pension Plan.

2.22 Participant. An Eligible Employee who agrees to be bound by the terms of this Plan by filing such form or forms, if any, as the Committee may require. Such term includes a Former Participant, a Rule of 55 Participant, a Transitional Participant and a Vested Participant as appropriate in the circumstances in which the term is used in the Plan.

2.23 Pension Plan. The Williams Pension Plan, as in effect on January 1, 2005 and as amended and/or restated from time to time. With respect to a Participant who has a benefit payable under the Williams Inactive Employees Pension Plan, as in effect January 1, 2005 and as amended and/or restated from time to time, such plan is also included within such term.

2.24 Pension Plan Benefit. The pension benefit actually paid during a Plan Year to the Participant or his Beneficiary (including a spouse or other contingent annuitant) pursuant to the benefit formula (set forth in Section 2.1 of the Pension Plan) which is applicable to such Participant and the method of payment selected by the Participant under such plan.

2.25 Plan. The Williams Companies Retirement Restoration Plan, effective as of January 1, 2008 as set forth in this and related documents which comprise the 409A Program and the Pre-409A Program and as amended and/or restated from time to time. The provisions of this document are generally effective for periods commencing on and after January 1, 2008 with respect to deferred amounts earned or vested after December 31, 2004 under the 409A Program as described in Article I. As described in Article I, vested benefits of Participants who were not receiving payment of vested benefits on December 31, 2004 are payable under the Pre-409A Program in a lump sum at the time specified in Article IV of The Williams Companies Supplemental Retirement Plan as in effect on December 31, 2004.

2.26 Plan Interest Rate. The rate of interest applicable under the terms of the Plan for determining Supplemental Interest Credits as of any Credit Date determined as the rate for the month of September immediately preceding the respective Plan Year in which the rate is applicable under the Plan, which rate is based upon the annual rate for 30-year Treasury securities as specified by the Commissioner of Internal Revenue in revenue rulings, notices and other guidance published in the Internal Revenue Bulletin.

2.27 Plan Year. Each twelve (12) consecutive month fiscal year beginning January 1 and ending December 31.

2.28 Rule of 55 Participant. A Vested Participant: (a) whose attained age in years and number of Years of Service credited as Benefit Service aggregated pursuant to the terms of the Pension Plan as of March 31, 1998 equaled at least fifty-five (55); (b) who is not a Transitional Participant; and (c) who incurs a Separation from Service after attaining age fifty-five (55) and is then eligible for an Early Pension pursuant to Section 5.2 of the Pension Plan.

2.29 Separation from Service. The Participant's termination or deemed termination from employment with the Company and its Affiliates. For purposes of determining whether a separation from service has occurred, the employment relationship is treated as continuing intact while the Participant is on military leave, sick leave or other bona fide leave of absence if the period of such leave does not exceed six (6) months, or if longer, so long as the Participant retains a right to reemployment with his or her employer under an applicable statute or by contract. For this purpose, a leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Participant will return to perform services for his or her employer. If the period of leave exceeds six (6) months and the Participant does not retain a right to reemployment under an applicable statute or by contract, the employment relationship will be deemed to terminate on the first date immediately following such six (6) month period. Notwithstanding the foregoing, if a leave of absence is due to any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than six (6) months, and such impairment causes the Participant to be unable to perform the duties of the Participant's position of employment or any substantially similar position of employment, a twenty-nine (29) month period of absence shall be substituted for such six (6) month period. For purposes of this Section 2.29, a separation from service occurs at the date as of which the facts and circumstances indicate either that, after such date: (A) the Participant and the Company reasonably anticipate the Participant will perform no further services for the Company and its Affiliates (whether as an employee or an independent contractor), or (B) that the level of bona fide services the Participant will perform for the Company and its Affiliates (whether as an employee or independent contractor) will permanently decrease to no more than twenty (20%) of the average level of bona fide services performed over the immediately preceding thirty-six (36) month period or, if the Participant has been providing services to the Company and its Affiliates for less than thirty-six (36) months, the full period over which the Participant has rendered services, whether as an employee or independent contractor. The determination of whether a separation from service has occurred shall be governed by the provisions of Treasury Regulation § 1.409A-1, as amended, taking into account the objective facts and circumstances with respect to the level of bona fide services performed by the Participant after a certain date.

2.30 Service Participant. A Vested Participant who is a "Service Participant" as such term is defined under the Pension Plan.

2.31 Supplemental Compensation Credit. The amount deemed credited to a Participant's Supplemental Pension Account based upon his Supplemental Retirement Compensation for a Plan Year (or any part of a Plan Year and for a disabled Participant accruing

Benefit Service credit or Compensation Credit pursuant to Section 5.3 of the Pension Plan, based upon his rate of Supplemental Retirement Compensation as of the date his Disability commenced), with such amount deemed to be credited as of the Credit Date for such Plan Year and determined in accordance with the following:

(a) Service Participant.

Age* on Credit Date	Credit Rate On Supplemental Retirement Compensation		Credit Rate On Supplemental Retirement Compensation Above Wage Base**		Credit Rate For Past Service*** On All Supplemental Retirement Compensation
Prior to 29	4.50%	+	1.00%	+	0.30% x Past Service
29	4.50%	+	See **** below	+	0.30% x Past Service
30 through 39	6.00%	+	2.00%	+	0.30% x Past Service
40 through 49	8.00%	+	3.00%	+	0.30% x Past Service
50 and older	10.00%	+	5.00%	+	0.30% x Past Service

(b) Nonservice Participant.

Age* on Credit Date	Credit Rate On Supplemental Retirement Compensation		Credit Rate On Supplemental Retirement Compensation Above Wage Base**
Prior to 29	4.50%	+	1.00%
29	4.50%	+	See **** below
30 through 39	6.00%	+	2.00%
40 through 49	8.00%	+	3.00%
50 and older	10.00%	+	5.00%

* Age means actual age measured in years attained as of the applicable Credit Date.

** Wage Base means the taxable wage base under the Federal Insurance Contributions Act applicable for the Plan Year of the applicable Credit Date (Plan Year of Disability for a disabled Participant accruing Compensation Credit pursuant to Section 5.3 of the Pension Plan).

*** Past Service means Benefit Service credited as of March 31, 1998.

**** For Plan Years beginning on or after January 1, 2002, and before January 1, 2008, the rate is 1.00% on Compensation up to 170 percent of the Wage base and the rate is 1.13% on Compensation greater than 170 percent of the Wage Base. For Plan Years beginning on or after January 1, 2008, the rate is 1.20% on Compensation above the Wage Base.

2.32 Supplemental Interest Credit. The amount deemed credited to a Participant's Supplemental Pension Account based upon the balance in his Supplemental Pension Account on the Credit Date in a Plan Year (prior to the inclusion of the Supplemental Compensation Credit, if any, for such Plan Year) multiplied by the Plan Interest Rate applicable for such Plan Year.

2.33 Supplemental Pension Account. A hypothetical account maintained for recordkeeping purposes only on behalf of a Participant to record the amount which would have accumulated if contributions had been made for each Plan Year of such Participant's active participation equal to his Supplemental Compensation Credit and if such contributions and Supplemental Interest Credits had accumulated with interest at the applicable Plan Interest Rate until his Benefit Starting Date.

2.34 Supplemental Retirement Benefit. The portion of a Participant's pension benefit under the 409A Program portion of this Plan determined in accordance with Article III for periods commencing on and after December 31, 2004, as described in Article I.

2.35 Supplemental Retirement Compensation. The portion of the total wages or salary, if any, which is in excess of Code Limitations paid to a Participant each Plan Year by an Employer or an affiliate, including Base Pay, short term disability ("STD") paid by an Employer, overriding royalties, amounts paid under a phantom override plan, bonuses (unless specifically excluded under a written bonus arrangement such as The Williams Companies, Inc. Executive Incentive Compensation Plan), if any, when paid, salary reduction amounts contributed to The Williams Investment Plus Plan, salary reduction amounts contributed to any qualified transportation plan established by the Company in accordance with Code Section 132(f)(4) or to any cafeteria plan or flexible benefits plan established by the Company in accordance with Code Section 125 and related sections of the Code, but excluding severance pay, cost of living pay, housing pay, relocation pay (including mortgage interest differential) and all such other taxable and non-taxable fringe benefits and extraordinary compensation, all as determined by the Committee, in its sole and absolute discretion. For purposes of determining "Average Monthly Compensation" and "Compensation Credits" under the Pension Plan, the Supplemental Retirement Compensation taken into account with respect to any Plan Year beginning on or after January 1, 2002, shall not exceed three (3) times such Participant's rate of Base Pay as of the last day of such Plan Year. For purposes of determining an "Accrued Benefit" under the Pension Plan, if a Participant is credited with less than two thousand eighty (2,080) "Hours of Service" under the Pension Plan for determining "Benefit Service" under the Pension Plan during a Plan Year, his Supplemental Retirement Compensation for that Plan Year shall be the product of his actual Supplemental Retirement Compensation for such Plan Year as described above multiplied by a fraction the numerator of which is two thousand eighty (2,080) and the denominator of which is the number of "Hours of Service" under the Pension Plan with which he is credited for such Plan Year.

2.36 Supplemental Survivor Pension. An amount payable in accordance with Section 5.1 to the Surviving Spouse or Beneficiary of a Vested Participant who died prior to the Benefit Starting Date of his Supplemental Retirement Benefit in a lump sum distribution determined by the balance of such Participant's Supplemental Pension Account at the date the amount of such distribution is determined.

2.37 Surviving Spouse. The person to whom a Participant is married on the date of his death and/or any former spouse to the extent provided in a qualified domestic relations order within the meaning of Code Section 414(p) and determined by the Committee to be effective with respect to the Participant's interest in the Plan; provided, however, a spouse shall not be a Surviving Spouse for purposes of eligibility for a Survivor Pension or other death benefit payable under Article V, unless such spouse was continuously married to the vested Participant on whose behalf such Survivor Pension or other death benefit is payable for the thirty (30) day period immediately prior to such vested Participant's death.

2.38 Termination of Employment. The date on which a Participant incurs a "Termination of Employment" as defined in Section 2.71 of the Pension Plan.

2.39 Transitional Participant. A Participant who (a) was a Participant and an Eligible Employee or a disabled Participant accruing Benefit Service pursuant to Section 5.3 of the Pension Plan on March 31, 1998 and April 1, 1998; (b) had attained at least age fifty (50) as of April 1, 1998; or (c) was a "Transitional Participant" under the terms of the Transco Energy Company Retirement Plan or the Texas Gas Retirement Plan, as defined under either such plan on the date his employment was directly transferred to an Employer.

2.40 Vested Participant. A Participant who is not a Transitional Participant and who is vested in his Basic Supplemental Benefit under the provisions of Article IV of this Plan.

ARTICLE III

Supplemental Retirement Benefits

3.1 Restoration of Credited Service for a Transitional Participant Following the recommencement of employment with an Employer by a Transitional Participant whose employment with an Employer was terminated at a time when such Transitional Participant had a

Supplemental Retirement Benefit and whose benefit had commenced to be paid, such Transitional Participant's subsequent Supplemental Retirement Benefit shall be reduced, but not below zero, by an amount which is the Actuarial Equivalent of the amount of Supplemental Retirement Benefit previously paid. If the Transitional Participant does not have a subsequent Supplemental Retirement Benefit, then the Transitional Participant shall not be required to reimburse this Plan with respect to any portion of the Supplemental Retirement Benefit previously paid to such Transitional Participant.

3.2 Cash Balance Supplemental Retirement Benefit for a Vested Participant. A Vested Participant's cash balance Supplemental Retirement Benefit shall be the amount credited to the Vested Participant's Supplemental Pension Account upon his Benefit Starting Date.

3.3 Cash Balance Supplemental Early Retirement Benefit. Solely with respect to a Rule of 55 Participant who incurs a Separation from Service with an Employer on or after age fifty-five (55), the amount credited to the Participant's Supplemental Pension Account shall be multiplied by the applicable percentage in the following schedule and any amount in excess of 100% of the Supplemental Pension Account shall be paid on the Benefit Starting Date.

Aggregate of Attained Age and Credited Benefit Service as of March 31, 1998	**Multiplier Percentage for Attained Age at Benefit Starting Date**			
	55 – 62	63	64	65
55 – 64	115%	115%	108%	100%
65 – 69	120%	120%	108%	100%
70 and over	125%	122%	108%	100%

3.4 Supplemental Disability Benefit. If the Disability of a Participant continues past age fifty-five (55), the amounts credited to such Participant's Supplemental Pension Account until age fifty-five (55) shall be distributed pursuant to the first or last sentences of Section 2.5, as applicable. Such Participant shall also be entitled to additional Supplemental Compensation Credits and Supplemental Interest Credits after age fifty-five (55) until the earlier of age sixty-five (65), or the cessation of the Disability for any reason including death. Any such additional supplemental disability credits shall be distributed upon the earlier of the first day of the month following the expiration of the three (3) month period commencing with the Participant's date of death (to the Participant's Beneficiary), or the first day of the month following the date the Participant attains age sixty-five (65).

ARTICLE IV

Vesting and Forfeitures

4.1 Vesting. A Participant shall become vested in his or her Supplemental Retirement Benefit in accordance with the same schedule and rules as are applicable in determining when he or she becomes vested in his or her Pension Plan Benefit.

4.2 Forfeitures. Any amount forfeited by a Participant who does not become vested in a benefit under this Plan shall constitute a reduction of the Employers' liability under this Plan and shall not be allocated to the remaining Participants.

ARTICLE V

Death Benefit

5.1 Cash Balance Supplemental Survivor Pension. The Surviving Spouse or other designated Beneficiary or Beneficiaries of a deceased, Vested Participant shall receive a Supplemental Survivor Pension with payments commencing on the Benefit Starting Date. Payment shall be made in accordance with a properly completed Beneficiary designation form provided by the Committee, signed and dated by such Participant and timely filed with the Committee (or its delegate). In the event a properly completed and timely filed Beneficiary designation form is not so filed or all designated Beneficiaries predeceased such Participant, payment shall be made to his Surviving Spouse, or, in the absence of a Surviving Spouse, to his estate which shall be deemed to be his Beneficiary.

5.2 Payment of Death Benefit. Any death benefit payable under this Article V shall be paid on the Benefit Starting Date in the form of a lump sum distribution.

5.3 Non-duplication of Benefits. If any payments are made pursuant to this Article V, no payments shall be made pursuant to any other provision of this Plan.

ARTICLE VI

Administration of the Plan

6.1 Administration by Committee. The Plan shall be administered by the Committee.

6.2 Operation of the Committee.

(a) The Committee shall act by a majority of its members constituting a quorum and such action may be taken either by a vote in a meeting or in writing without a meeting. A quorum shall consist of a majority of the members of the Committee. No Committee member shall act upon any question pertaining solely to himself, and with respect to any such question only the other Committee members shall act.

(b) The Committee may allocate responsibility for the performance of any of its duties or powers to one or more Committee members or employees of the Employers.

(c) The Committee or its designee shall keep such books of account, records and other data as may be necessary for the proper administration of the Plan.

6.3 Powers and Duties of the Committee. The Committee shall be generally responsible for the operation and administration of the Plan. To the extent that powers are not delegated to others pursuant to provisions of this Plan, the Committee shall have such powers as may be necessary to carry out the provisions of the Plan and to perform its duties hereunder, including, without limiting the generality of the foregoing, the power:

(a) To appoint, retain and terminate such persons as it deems necessary or advisable to assist in the administration of the Plan or to render advice with respect to the responsibilities of the Committee under the Plan, including accountants, actuaries, administrators, attorneys and physicians.

(b) To make use of the services of the employees of the Employers in administrative matters.

(c) To obtain and act on the basis of all tables, valuations, certificates, opinions, and reports furnished by the persons described in paragraph (a) or (b) above. Any determination of Actuarial Equivalent benefits by the actuary selected by the Company or the Committee shall be conclusive and binding on the Employers, the Committee and all Participants, Former Participants and Beneficiaries.

(d) To review the manner in which benefit claims and other aspects of the Plan administration have been handled by the employees of the Employers.

(e) To determine all benefits and resolve all questions pertaining to the administration and interpretation of the Plan provisions, either by rules of general applicability or by particular decisions. To the maximum extent permitted by law, all interpretations of the Plan and other decisions of the Committee shall be conclusive and binding on all parties.

(f) To adopt such forms, rules and regulations as it shall deem necessary or appropriate for the administration of the Plan and the conduct of its affairs, provided that any such forms, rules and regulations shall not be inconsistent with the provisions of the Plan.

(g) To remedy any inequity resulting from incorrect information received or communicated or from administrative error.

(h) To commence or defend any litigation arising from the operation of the Plan in any legal or administrative proceeding.

6.4 Required Information. Any Participant or Former Participant and any Beneficiary eligible to receive benefits under the Plan shall furnish to the Committee any information or proof requested by the Committee and reasonably required for the proper administration of the Plan. Failure on the part of the Participant, Former Participant or Beneficiary to comply with any such request within a reasonable period of time shall be sufficient grounds for delay in the payment of benefits under the Plan until such information or proof is received by the Committee.

6.5 Compensation and Expenses. All expenses incident to the operation and administration of the Plan reasonably incurred, including, without limitation by way of specification, the fees and expenses of attorneys and advisors, and for such other professional, technical and clerical assistance as may be required, shall be paid by the Employers. Members of the Committee shall not be entitled to any compensation by virtue of their services as such nor be required to give any bond or other security; provided, however, that they shall be entitled to reimbursement by the Employers for all reasonable expenses which they may incur in the performance of their duties hereunder and in taking such action as they deem advisable hereunder within the limits of the authority given them by the Plan and by law.

6.6 Indemnification. To the extent provided for in the Company by-laws, each Employer shall indemnify and hold harmless each member of the Board, each member of the

Committee, and each officer and employee of an Employer to whom are delegated duties, responsibilities, and authority with respect to this Plan against all claims, liabilities, fines and penalties, and all expenses reasonably incurred by or imposed upon him (including but not limited to reasonable attorney fees) which arise as a result of his actions or failure to act in connection with the operation and administration of this Plan to the extent lawfully allowable and to the extent that such claim, liability, fine, penalty, or expense is not paid for by liability insurance purchased or paid for by an Employer. Notwithstanding the foregoing, an Employer shall not indemnify any person for any such amount incurred through any settlement or compromise of any action unless the Employer consents in writing to such settlement or compromise.

6.7 Claims Procedure. The Committee as constituted and serving from time to time shall adopt, and may change from time to time, claims procedures, provided that such claims procedures and changes thereof shall conform with Section 503 of the Employee Retirement Income Security Act of 1974, as amended, and regulations promulgated thereunder. Such claims procedures, as in effect from time to time shall be deemed to be incorporated herein and made a part hereof.

ARTICLE VII

Miscellaneous

7.1 Benefits Payable by the Employers. All benefits payable under this Plan shall constitute an unfunded obligation of the Employers. Payments shall be made, as due, from the general funds of the Employers. The Employers, at their option, may maintain one or more bookkeeping reserve accounts to reflect their obligations under the Plan and may make such investments as they, or any of them, may deem desirable to assist in meeting such obligations.

Any such investments shall be assets of the Employers subject to claims of general creditors. No person eligible for a benefit under this Plan shall have any right, title or interest in any such investments.

7.2 Amendment or Termination. The Committee is authorized to amend the Plan, if such amendment does not increase the costs of the Plan and the Board is authorized to amend, modify, restate or terminate the Plan; provided, however, that (i) no such action by the Committee or the Board shall reduce a Participant's Supplemental Retirement Benefit accrued as of the time thereof, and (ii) any such amendments, modifications, restatement or termination shall be effectuated in a manner which will not result in the imposition of Code Section 409A penalties. Generally, the amendment or termination of the Pre-409A Program shall be effectuated in a manner which either (A) avoids causing the "Grandfathered Benefits" to be materially modified within the meaning of Treas. Reg. 1.409A-6(a)(4); or (B) causes the Pre-409A Program to meet the requirements of Code Section 409A without the imposition of Code Section 409A penalties. In this regard, upon termination of the 409A Program due to a Change in Control, the Pre-409A Program shall be terminated either pursuant to Treas. Reg. 1.409A-6(a)(4)(iii), or pursuant to a plan termination amendment which causes the Pre-409A Program to comply with Code Section 409A. The date of such termination shall be the first business day. Payments under the 409A Program may be accelerated only to the extent permitted by Treas. Reg. 1.409A-3(j)(4). In this regard, if a Change in Control occurs, the service recipient entity that will be primarily liable immediately after the Change in Control transaction for the payment of benefits under the 409A Program shall terminate the 409A Program and all other nonaccount plans which are aggregated with the 409A Program under Treas. Reg. 1-409A-3(j)(4)(ix). The date of such termination shall be the first business day following such Change in Control and all amounts held in the Plan for any Participant shall be distributed in a lump sum within ten (10) business days after such termination.

7.3 Status of Employment. Nothing herein contained shall be deemed: (a) to give to any Participant the right to be retained in the employ of any Employer, subsidiary or affiliate; (b) to affect the right of any Employer to discipline or discharge any Participant at any time; (c) to give any Employer, subsidiary or affiliate the right to require any Participant to remain in its employ; or (d) to affect any Participant's right to terminate his or her employment at any time.

7.4 Payments to Minors and Incompetents. If a Participant, Former Participant or Beneficiary entitled to receive any benefits hereunder is a minor or is deemed by the Committee or is adjudged to be legally incapable of giving a valid receipt and discharge for such benefits, they will be paid to the duly appointed guardian of such minor or incompetent or to such other person or entity as the Committee may designate. Such payment shall, to the extent made, be deemed a complete discharge of any liability for such payment under the Plan.

7.5 Inalienability of Benefits. The right of any person to any benefit or payment under the Plan shall not be subject to voluntary or involuntary transfer, alienation or assignment, and, to the fullest extent permitted by law, shall not be subject to attachment, execution, garnishment, sequestration or other legal or equitable process. In the event a person who is receiving or is entitled to receive benefits under the Plan attempts to assign, transfer or dispose of such right, or if an attempt is made to subject said right to such process, such assignment, transfer or disposition shall be null and void.

7.6 Qualified Domestic Relations Orders. If a qualified domestic relations order is applicable to a Participant's Pension Plan Benefit, such Participant's Pension Plan Benefit shall be deemed to be the amount which would have otherwise been payable to the Participant from the Pension Plan if such qualified domestic relations order never existed.

7.7 Governing Law. Except to the extent preempted by federal law, the Plan shall be governed by and construed in accordance with the laws of the State of Oklahoma.

7.8 Procedure for Adoption. Any corporation which is a contributing employer under the Pension Plan may, by resolution of such corporation's board of directors, adopt the Plan subject to such terms and conditions as may be required by the Committee consistent with the provisions of the Plan.

Executed in 0 counterpart originals this 1st day of December, 2008, effective as hereinbefore provided.

THE WILLIAMS COMPANIES, INC.

By: /s/ Stephanie Cipolla
Title: Vice President Human Resources

TABLE OF CONTENTS

Exhibit 10.9

2008 RESTRICTED STOCK UNIT AGREEMENT

THIS RESTRICTED STOCK UNIT AGREEMENT (this “Agreement”), which contains the terms and conditions for the Restricted Stock Units (“Restricted Stock Units” or “RSUs”) referred to in the 2008 Restricted Stock Unit Award Letter delivered in hard copy or electronically to Participant (“2008 Award Letter”), is by and between **THE WILLIAMS COMPANIES, INC.,** a Delaware corporation (the “Company”) and the individual identified on the last page hereof (the “Participant”).

1. Grant of RSUs. Subject to the terms and conditions of The Williams Companies, Inc. 2007 Incentive Plan, as amended from time to time (the “Plan”), this Agreement and the 2008 Award Letter, the Company hereby grants an award (the “Award”) to the Participant of **<@Num+C @>** RSUs effective **<@GrDt+C@>** (the “Effective Date”). The Award gives the Participant the right to receive the number of shares of the Common Stock of the Company equal to the number of RSUs shown in the prior sentence, subject to adjustment under the terms of this Agreement. These shares are referred to in this Agreement as the “Shares.” Until the Participant receives payment of the Shares under the terms of Paragraph 4, the Participant shall have no rights as a stockholder of the Company with respect to the Shares.

2. Incorporation of Plan. The Plan is hereby incorporated herein by reference and all capitalized terms used herein which are not defined in this Agreement shall have the respective meanings set forth in the Plan. The Participant acknowledges that he or she has received a copy of, or has online access to, the Plan and hereby accepts the RSUs subject to all the terms and provisions of the Plan and this Agreement.

3. Board Decisions and Interpretations. The Participant hereby agrees to accept as binding, conclusive and final all actions, decisions and/or interpretations of the Board, its delegates, or agents, upon any questions or other matters arising under the Plan or this Agreement.

4. Payment of Shares.

(a) Except as otherwise provided in Subparagraph 4(b) below, the Participant shall receive payment of all Shares on the date that is three years after the Effective Date (not including the Effective Date) (the “Maturity Date”). For example, if the Effective Date of the Participant’s award under this Agreement is May 17, 2008, the Maturity Date will be May 17, 2011.

(b) If the Participant dies prior to the Maturity Date while serving as a Non-Management Director of the Company or his or her service as a Non-Management Director of the Company terminates for any other reason prior to the Maturity Date and such termination constitutes a “separation from service” as defined under Treasury Regulation § 1.409A-1, as amended, the Participant shall receive payment of all Shares at the time of such death or separation from service. In this regard, if at the time a Non-Management Director’s service as a Non-Management Director terminates, such

Non-Management Director is also providing services to the Company or an Affiliate (as defined below) as an independent contractor, no separation from service by such Non-Management Director shall occur and no Shares shall be payable to such Non-Management Director until the date on which such Non-Management Director has a Separation from Service as an Independent Contractor (as defined below) from the Company and its Affiliates.

(c) All Shares that are paid pursuant to the Participant's death or separation from service Subparagraph 4(b) above shall be paid to the Participant upon occurrence of the event giving rise to the right to payment or, in the case of Participant's death, to the beneficiary of the Participant under the Plan or, if no beneficiary has been designated, to the Participant's estate, *provided that*, except as otherwise required under Federal securities laws or other applicable law, all Shares that are paid pursuant to Subparagraph 4(b) above shall be paid not more than 90 days following the occurrence of the event giving rise to the right to payment.

(d) Shares that become payable under this Agreement will be paid by the Company by the delivery to the Participant, or, in the case of the Participant's death, to the Participant's beneficiary or legal representative, of one or more certificates (or other indicia of ownership) representing shares of Williams Common Stock equal in number to the number of Shares otherwise payable under this Agreement.

(e) Upon conversion of RSUs into Shares under this Agreement, such RSUs shall be cancelled.

5. Definitions. As used in this Agreement, the following terms shall have the definitions set forth below.

(a) "Affiliate" means all persons with whom the the Company would be considered a single employer under Section 414(b) of the Code, and all persons with whom such person would be considered a single employer under Section 414(c) of the Code.

(b) "Separation from Service as an Independent Contractor" will occur upon the expiration of the contract (or in the case of more than one contract, all contracts) under which services are performed by a Non-Management Director for the Company or an Affiliate, but only if the expiration constitutes a good-faith and complete termination of the contractual relationship. An expiration of a contract shall not constitute a good faith and complete termination of the contractual relationship if the Company or an Affiliate anticipates either a renewal of a contractual relationship or the Non-Management Director's becoming an employee. The determination of whether a Separation from Service as an Independent Contractor has occurred shall be governed by the provisions of Treasury Regulation § 1.409A-1, as amended.

6. Other Provisions.

(a) The Participant understands and agrees that payments under this Agreement shall not be used for, or in the determination of, any other payment or benefit under any continuing agreement, plan, policy, practice or arrangement providing for the making of any payment or the provision of any benefits to or for the Participant or the Participant's beneficiaries or representatives, including, without limitation, any employment agreement, any change of control severance protection plan or any employee benefit plan as defined in Section 3(3) of ERISA, including, but not limited to qualified and non-qualified retirement plans.

(b) The Participant agrees and understands that, upon payment of Shares under this Agreement, stock certificates (or other indicia of ownership) issued may be held as collateral for monies he/she owes to Company or any of its Affiliates, including but not limited to personal loan(s) or Company credit card debt.

(c) RSUs, Shares and the Participant's interest in RSUs and Shares may not be sold, assigned, transferred, pledged or otherwise disposed of or encumbered at any time prior to the Participant's becoming entitled to payment of Shares under this Agreement.

(d) With respect to the right to receive payment of the Shares under this Agreement, nothing contained herein shall give the Participant any rights that are greater than those of a general creditor of the Company.

(e) The obligations of the Company under this Agreement are unfunded and unsecured. Each Participant shall have the status of a general creditor of the Company with respect to amounts due, if any, under this Agreement.

(f) The parties to this Agreement intend that this Agreement meet the applicable requirements of Section 409A of the Code and recognize that it may be necessary to modify this Agreement and/or the Plan to reflect guidance under Section 409A of the Code issued by the Internal Revenue Service. Participant agrees that the Board shall have sole discretion in determining (i) whether any such modification is desirable or appropriate and (ii) the terms of any such modification.

(g) The Participant shall become a party to this Agreement by accepting the Award either electronically or in writing in accordance with procedures of the Board, its delegates or agents.

(h) Nothing in this Agreement or the Plan shall confer upon the Participant the right to continue to serve as a director of the Company.

7. Notices. All notices to the Company required hereunder shall be in writing and delivered by hand or by mail, addressed to The Williams Companies, Inc., One Williams Center, Tulsa, Oklahoma 74172, Attention: Stock Administration Department. Notices shall become effective upon their receipt by the Company if delivered in the foregoing manner. To direct the sale of any Shares issued under this Agreement, the Participant must contact Fidelity at http://netbenefits.fidelity.com or by telephone at 800-544-9354.

8. Tax Consultation. You understand you will incur tax consequences as a result of acquisition or disposition of the Shares. You agree to consult with any tax consultants you think advisable in connection with the acquisition of the Shares and acknowledge that you are not relying, and will not

rely, on the Company for any tax advice.

THE WILLIAMS COMPANIES, INC.

By: ______________________________

Steven J. Malcolm
President and CEO

Participant: **<@Name**
SSN: **<@SSN @>**

Exhibit 10.11

AMENDMENT TO
THE WILLIAMS COMPANIES, INC. 2002 INCENTIVE PLAN
(AS AMENDED AND RESTATED EFFECTIVE JANUARY 23, 2004)
AND AWARD AGREEMENTS THEREUNDER

This Amendment ("Amendment") to The Williams Companies, Inc. 2002 Incentive Plan (as amended and restated effective January 23, 2004) ("Plan"), and to Award Agreements pursuant to which Awards have previously been made thereunder, is hereby adopted effective the 26th day of January, 2007.

WHEREAS, Section 4.2 of the Plan provides that upon the occurrence of certain events, adjustments may be made to (a) the number and type of Shares (or other securities or property) with respect to which Awards may be granted under the Plan, (b) the number and type of Shares (or other securities or property) subject to outstanding Awards, (c) the grant or exercise price with respect to any award under the Plan or provision made for a cash payment to the holder of an outstanding Award, (d) the number and kind of Shares of outstanding Restricted Shares or relating to any other outstanding Award in connection with which Shares are subject, and (e) the number of Shares with respect to which Awards may be granted to a Grantee; and

WHEREAS, the Board of Directors of the Company has determined that it is in the best interest of the Company to provide protection against both dilution and accretion of Awards and greater assurance of the continued ability of the Company to make Awards under the Plan upon the occurrence of certain events;

NOW, THEREFORE, the Plan and each Award Agreement pursuant to which Awards under the Plan have been granted and remain outstanding are hereby amended as follows:

1. Section 4.2 of the Plan is amended and restated in its entirety to read as follows:

4.2 Adjustments in Authorized Shares and Awards. In the event of any dividend or other distribution (whether in the form of cash, Shares, or other property, but excluding regular, quarterly cash dividends), recapitalization, forward or reverse stock split, subdivision, consolidation or reduction of capital, reorganization, merger, consolidation, scheme of arrangement, split-up, spin-off or combination involving the Company or repurchase or exchange of Shares or other securities of the Company or other rights to purchase Shares or other securities of the Company, or other similar corporate transaction or event that affects the Shares, provided that any such transaction or event referred to heretofore does not involve the receipt of consideration by the Company, then the Committee shall, in such manner as it deems equitable in order to prevent dilution or enlargement of the benefits or potential benefits intended to be made available under the Plan, adjust (a) the number and type of Shares (or other securities or property) with respect to which Awards may be granted, (b) the number and type of Shares (or other securities or property) subject to outstanding Awards, (c) the grant or exercise price with respect to any Award or, if deemed appropriate, make provision for a cash payment to the holder of an outstanding Award, (d) the number and kind of outstanding Shares of Restricted Stock or relating to any other outstanding Award in connection with which Shares are subject, (e) the number of Shares with respect to which Awards may be granted to a Grantee, as set forth in Section 4.3 and (f) the number of Shares subject to outstanding Restricted Stock Units granted under Section 13.5; *provided*, in each case, that with respect to Awards of Incentive Stock Options intended as of the grant date to qualify as Incentive Stock Options, no such adjustment shall be authorized to the extent that such adjustment would cause the Plan to violate Section 422(b)(1) of the Code; and *provided further* that the number of Shares subject to any Award denominated in Shares shall always be a whole number. By way of example and not limitation, neither the conversion of any convertible securities of the Company nor the open market purchase of Shares by the Company shall be treated as a transaction that "does not involve the receipt of consideration" by the Company.

2. Each Award Agreement pursuant to which an Award was made under the Plan and that remains outstanding as of the date this Amendment is hereby amended to incorporate Section 4.2 as amended and restated as set forth in Paragraph 1 above, but only to the extent that application of such amendment would not adversely affect such Award in any material way.

3. Except as set forth in Paragraphs 1 and 2 above, the Plan and Award Agreement and all of their respective terms and conditions shall continue in effect.

4. All capitalized terms in this Amendment shall have the meanings set forth in the Plan except to the extent otherwise defined herein.

This Amendment is hereby approved and adopted effective as of the date first set forth above.

AMENDMENT NO. 2
TO
THE WILLIAMS COMPANIES, INC. 2002 INCENTIVE PLAN
(AS AMENDED AND RESTATED EFFECTIVE JANUARY 23, 2004),
AWARD AGREEMENTS AND DEFERRAL ELECTIONS THEREUNDER

This Amendment No. 2 (“Amendment”) to The Williams Companies, Inc. 2002 Incentive Plan (as amended and restated effective January 23, 2004) and as further amended (“Plan”) is hereby adopted effective the 20th day of November, 2008.

WHEREAS, in October 2004, Congress adopted Section 409A of the Internal Revenue Code of 1986, as amended (the “Code”);

WHEREAS, final regulations to Section 409A of the Code become fully effective January 1, 2009 (Section 409A of the Code and such final regulations and other guidance thereunder being referred to below in the aggregate as “Section 409A); and

WHEREAS, certain Awards made under the Plan remain outstanding and, together with the Plan, must comply with Section 409A beginning January 1, 2009;

WHEREAS, the Board of Directors of the Company has determined that it is in the best interest of the Company to amend the Plan to comply with Section 409A;

NOW, THEREFORE, the Plan is hereby amended as follows:

1. Section 2.44 is amended to add the following at the end of the Section:

   Notwithstanding the foregoing, except as otherwise provided in the Award Agreement with respect to such Award, with respect to any Award subject to Section 409A of the Code, “Termination of Affiliation” shall mean a “separation from service” as defined in Section 409A of the Code and guidance thereunder.

2. Section 5.8 is amended to add the following at the end of the Section:

   Notwithstanding anything herein to the contrary, in no event will any deferral or payment of a deferred number of Shares or any other payment with respect to any Award be allowed if the Committee determines, in its sole discretion, that the deferral would result in the imposition of the additional tax under Section 409A(a)(1)(B) of the Code.

3. Section 13.5(a) is amended to add the following to the end of the second sentence of the Section:

,including, but not limited to, restrictions designed to comply with the requirements of Section 409A of the Code.

4. The last sentence of Section 13.6(e) is deleted and is replaced in its entirety by the following sentence:

Such settlement shall be made at the time or times specified in the applicable Deferral Election; *provided* that a Non-Employee Director may further defer settlement of the Deferral Account by filing a new Deferral Election subject to such restrictions and advance filing requirements as the Company may impose, including, but not limited to, restrictions designed to comply with the requirements of Section 409A of the Code.

5. A new Section 16.20 is added to read in its entirety as follows:

16.20 Code Section 409A Compliance. The Board intends that, except as may be otherwise determined by the Committee, any Awards under the Plan satisfy the requirements of Section 409A of the Code and related regulations and Treasury pronouncements ("Section 409A") to avoid the imposition of any taxes, including additional income taxes, thereunder. If the Committee determines that an Award, Award Agreement, payment, distribution, deferral election, transaction or any other action or arrangement contemplated by the provisions of the Plan would, if undertaken, cause a Grantee to become subject to Section 409A, unless the Committee expressly determines otherwise, such Award, Award Agreement, payment, distribution, deferral election, transaction or other action or arrangement shall not be undertaken and the related provisions of the Plan and/or Award Agreement and/or deferral election will be deemed modified, or, if necessary, rescinded in order to comply with the requirements of Section 409A to the extent determined by the Committee without the consent of or notice to the Grantee. Notwithstanding the foregoing, with respect to any Award intended by the Committee to be exempt from the requirements of Section 409A which is to be paid out when vested, such payment shall be made as soon as administratively feasible after the Award became vested, but in no event shall such payment be made later than 2-1/2 months after the end of the calendar year in which the Award became vested unless (a) deferred pursuant to Section 5.8 or (b) otherwise permitted under the exemption provisions of Section 409A.

6. Except as set forth in Paragraphs 1 through 5 above, the Plan, each Award Agreement and/or each deferral election and all of their respect terms and conditions shall continue in effect.

7. All capitalized terms in this Amendment shall have the meanings set forth in the Plan except to the extent otherwise defined herein.

This Amendment is hereby approved and adopted effective as of the date first set forth above.

/s/ Stephanie Cipolla   Date: 12/1/08

**AMENDMENT NO. 1
TO
THE WILLIAMS COMPANIES, INC. 2007 INCENTIVE PLAN**

This Amendment No. 1 (“Amendment”) to The Williams Companies, Inc. 2007 Incentive Plan (“Plan”) is hereby adopted effective the 20th day of November, 2008.

WHEREAS, in October 2004, Congress adopted Section 409A of the Internal Revenue Code of 1986, as amended (the “Code”);

WHEREAS, final regulations to Section 409A of the Code become fully effective January 1, 2009 (Section 409A of the Code and such final regulations and other guidance thereunder being referred to below in the aggregate as “Section 409A”); and

WHEREAS, the Board has determined that it is in the best interest of the Company to amend the Plan to(a) further reflect the Company’s intent that the Plan and Awards thereunder comply with Section 409A and (b) change certain provisions of the Plan relating to Change in Control;

NOW, THEREFORE, the Plan is hereby amended as follows:

1. The last sentence of Section 2.48 is deleted and replaced in its entirety with the following:

Notwithstanding the foregoing, except as otherwise provided in the Award Agreement with respect to such Award, with respect to an Award subject to Section 409A of the Code, “Termination of Affiliation” shall mean a “separation from service” as defined in Section 409A of the Code and guidance thereunder.

2. Section 14.1 of the Plan is amended by deleting the phrase “, but not during a Merger of Equals Period,” from the first sentence.

3. Section 14.2(d) is amended and restated in its entirety to read as follows:

(d) “Good Reason” means, unless otherwise defined in an Award Agreement or individual employment, change in control or other severance agreement, the occurrence, within two years following a Change in Control and without a Grantee’s prior written consent, of any one or more of the following:

(i) a material adverse reduction in the nature or scope of the Grantee's duties from the most significant of those assigned at any time in the 90-day period prior to a Change in Control; or

(ii) a significant reduction in the authority and responsibility assigned to the Grantee; or

(iii) any reduction in or failure to pay Grantee's base salary; or

(iv) a material reduction of Grantee's aggregate compensation and/or aggregate benefits from the amounts and/or levels in effect on the Change Date, unless such reduction is part of a policy applicable to peer employees of the Employer and of any successor entity;

(v) a requirement by the Company or an Affiliate that the Grantee's principal duties be performed at a location more than fifty (50) miles from the location where the Grantee was employed immediately preceding the Change in Control, without the Grantee's consent (except for travel reasonably required in the performance of the Grantee's duties); provided such new location is farther from Grantee's residence than the prior location; or

(vi) the failure of the Surviving Corporation following a Reorganization Transaction to assume all Awards previously made under the Plan or to provide equivalent awards of substantially the same value.

Notwithstanding anything in this Article 14 to the contrary, no act or omission shall constitute grounds for "Good Reason":

(i) Unless, at least 30 days prior to his termination, Grantee gives a written notice to the Company or the Affiliate that employs Grantee of his intent to terminate his employment for Good Reason which describes the alleged act or omission giving rise to Good Reason;

(ii) Unless such notice is given within 90 days of Grantee's first actual knowledge of such act or omission; and

(iii) Unless the Company or the Affiliate that employs Grantee fails to cure such act or omission within the 30 day period after receiving such notice.

Further, no act or omission shall be "Good Reason" if Grantee has consented in writing to such act or omission.

4. Section 14.2(e)(ii) is amended by deleting the phrase "(or by a simple majority for purposes of subsection (b) of the definition of 'Merger of Equals')."

5. Section 14.2(f) is deleted in its entirety.

6. Section 14.2(g) is deleted in its entirety.

7. Section 15.3(e) is amended by deleting in full the proviso at the end of the last sentence of such Section.

8. Except as set forth in Paragraphs 1 through 7 above, the Plan and its terms and conditions shall continue in effect.

9. Notwithstanding anything to the contrary in the Plan or in any Award Agreement, this Amendment shall not be incorporated into nor amend or change in any respect the terms of any Award or Award Agreement outstanding on the effective date hereof.

10. All capitalized terms in this Amendment shall have the meanings set forth in the Plan except to the extent otherwise defined herein.

This Amendment is hereby approved and adopted effective as of the date first set forth above.

/s/ Stephanie Cipolla Date: 12/1/08

AMENDMENT TO
THE WILLIAMS COMPANIES, INC. 2007 EMPLOYEE STOCK PURCHASE PLAN

WHEREAS, The Williams Companies, Inc. (the "Company") maintains The Williams Companies, Inc. 2007 Employee Stock Purchase Plan, effective as of May 17, 2007, as subsequently amended (the "Plan"); and

WHEREAS, in accordance with the terms of the Plan the Compensation Committee may designate the Designated Subsidiaries that may participate in the Plan; and make certain other Plan amendments

WHEREAS, at its September 18, 2007 meeting, consistent with the changes below, the Compensation Committee adopted the following changes to the Plan;

NOW THEREFORE, the Plan is hereby amended as follows effective as provided herein:

I.

Section 6(a) of the Plan is amended in its entirety to provide as follows:

"6. **Method of Payment of Contributions**.

(a) Subject to the limitations set forth in Section 3(b), a participant shall elect at the time and manner prescribed by the Designated Broker to have payroll deductions made on each payday during the Offering Period in an dollar amount of not less than $10.00 but not to exceed $576 per payday (or such greater amount as the Compensation Committee may establish from time to time before an Offering Date) of such participant's Compensation on each payday during the Offering Period; provided further that once such election has been made and the Offering Period begins, the participant may not increase such election amount during such Offering Period and may decrease such election amount only as detailed in Section 6(b) or elsewhere in this Plan. All payroll deductions made by a participant shall be credited to his or her account under the Plan. A participant may not make any additional payments into such account. Further, the maximum payroll deductions that a participant may elect per Offering Period shall not exceed $7,500 (provided that in the first offering period from October 1, 2007 through December 31, 2007, the maximum payroll deductions that a participant may elect per Offering Period shall not exceed $3,456) and the maximum payroll deductions that a participant may elect for any calendar year shall not exceed $15,000 (or, subject to the limitations set forth in Section 3(b), such greater amount as the Compensation Committee may establish from time to time before an Offering Date). Finally, subject to the preceding sentence and to the limitations set forth in Section 3(b), a participant (i) who has elected to participate in the Plan pursuant to this Section 6(a) for an Offering Period and (ii) who takes no action to change or revoke such election, for the next following

Offering Period and/or for any subsequent Offering Period prior to the Offering Date for any such respective Offering Period shall be deemed to have made the same election, including the same attendant payroll deduction authorization, for such next following and/or subsequent Offering Periods as was in effect immediately prior to such respective Offering Date; provided further that any participant who has elected to participate in the Plan for the first Offering Period who takes no action to change or revoke such election, for the next following Offering Period and/or for any subsequent Offering Period prior to the Offering Date for any such respective Offering Period shall be deemed to have made the same payroll deduction authorization for such next following and/or subsequent Offering Periods as was in effect immediately prior to such respective Offering Date.

II.

Effective September 18, 2007, Appendix A of the Plan is amended in its entirety to provide as follows:

"APPENDIX A-DESIGNATED SUBSIDIARIES

The Williams Companies, Inc.
Cardinal Operating Company
Gas Supply, L.L.C.
Williams Express, Inc.
Williams Alaska Petroleum, Inc.
Williams Natural Gas Liquids, Inc.
Marsh Resources, Inc.
Northwest Pipeline Services LLC
Pine Needle Operating Company
TouchStar Technologies L.L.C.
Transco Energy Company
Transco Services LLC
WFS – Liquids Company
WFS – Pipeline Company
Williams Gulf Coast Gathering Company, LLC
Williams Field Services Company, LLC
Williams Production Company, LLC
Williams Energy Services, LLC
Williams Field Services Group, LLC
Williams One-Call Services, Inc.
Williams Headquarters Building Company
Williams Relocation Management, Inc.
Williams Acquisition Holding Company, Inc.
Williams Wireless, Inc.
Williams Information Technology, Inc.
Williams Petroleum Services, LLC

FT&T
Williams Power Company, Inc.
Williams International Company
Williams Refining & Marketing LLC
Williams Midstream Natural Gas Liquids, Inc.
Williams Exploration Company
Williams Gas Pipeline Company, LLC
MAPCO Inc.
Williams WPC-I, Inc.
Williams WPC-II, Inc.”

III.

Except as modified herein, the Plan shall remain in full force and effect.

Exhibit 10.17

AMENDMENT TO
THE WILLIAMS COMPANIES, INC. 2007 EMPLOYEE STOCK PURCHASE PLAN

WHEREAS, The Williams Companies, Inc. (the "Company") maintains The Williams Companies, Inc. 2007 Employee Stock Purchase Plan, effective as of May 17, 2007, as subsequently amended (the "Plan"); and

WHEREAS, in accordance with the terms of the Plan the Compensation Committee may designate the Designated Subsidiaries that may participate in the Plan; and make certain other Plan amendments

WHEREAS, at its January 21st, 2009 meeting, consistent with the changes below, the Compensation Committee adopted the following changes to the Plan;

NOW THEREFORE, the Plan is hereby amended as follows effective as provided herein:

I.

Effective January 1, 2009, Appendix A of the Plan is amended in its entirety to provide as follows:

"APPENDIX A-DESIGNATED SUBSIDIARIES

The Williams Companies, Inc.
Cardinal Operating Company (known as Cardinal Operating Company, LLC effective December 31, 2008)
Gas Supply, L.L.C.
Williams Express, Inc.
Williams Alaska Petroleum, Inc.
Williams Natural Gas Liquids, Inc.
Marsh Resources, Inc. (known as Marsh Resources, LLC effective December 31, 2008)
Northwest Pipeline Services LLC
Pine Needle Operating Company (known as Pine Needle Operating Company, LLC effective December 31, 2008)
TouchStar Technologies L.L.C.
Transcontinental Gas Pipe Line Corporation (known as Transcontinental Gas Pipe Line Company, LLC effective December 31, 2008)
Transco Energy Company (known as Transco Energy Company, LLC effective December 30, 2008)
Transco Services LLC
WFS – Liquids Company
WFS – Pipeline Company

Williams Gulf Coast Gathering Company, LLC
Williams Field Services Company, LLC
Williams Production Company, LLC
Williams Energy Services, LLC
Williams Field Services Group, LLC
Williams One-Call Services, Inc.
Williams Headquarters Building Company
Williams Relocation Management, Inc.
Williams Acquisition Holding Company, Inc.
Williams Wireless, Inc.
Williams Information Technology, Inc.
Williams Petroleum Services, LLC
FT&T, Inc.
Williams Power Company, Inc.
Williams International Company
Williams Refining & Marketing LLC
Williams Midstream Natural Gas Liquids, Inc.
Williams Exploration Company
Williams Gas Pipeline Company, LLC
MAPCO Inc.
Williams WPC-I, Inc.
Williams WPC-II, Inc."

III.

Except as modified herein, the Plan shall remain in full force and effect.

Exhibit 10.18

The Williams Companies, Inc.

Amended And Restated
Change In Control Severance Agreement

(Tier One Executives)

The Williams Companies, Inc.
Amended And Restated
Change in Control Severance Agreement

(Tier One Executives)

Table of Contents

The Williams Companies, Inc.

Amended And Restated Change-In-Control Severance Agreement

THIS AMENDED AND RESTATED AGREEMENT dated as of__________, 200___ (the "Agreement Date") is made by and between The Williams Companies, Inc., a corporation incorporated under the laws of the State of Delaware ("Williams", together with its subsidiaries, affiliates and successors thereto) and [INSERT EXECUTIVE NAME] ("Executive").

RECITALS

The Board of Directors of Williams (the "Board") has determined that it is in the best interests of Williams and its shareholders to encourage and motivate the Executive to devote his full attention to the performance of his assigned duties without the distraction of concerns regarding his involuntary or constructive termination of employment due to a Change in Control of Williams. The Executive is employed by Williams or a Subsidiary and may from time to time be employed by one or more Subsidiaries. Williams and its Subsidiaries believe that it is in the best interest of the Executive, their customers, the communities they serve, and the stockholders of Williams to provide financial assistance through severance payments and other benefits to Executive if Executive is involuntarily or constructively terminated upon or within a certain period after a Change in Control. This Agreement is intended to accomplish these objectives.

This Agreement supersedes and replaces all other written or oral exchanges, agreements, understandings, or arrangements between or among Executive and Williams and/or the Subsidiary entered into prior to the date hereof and relating to severance or benefits in relation to a Change in Control, including, but not limited to The Williams Companies, Inc. Change in Control Severance Protection Plan as effective January 1, 1990 and amended and restated June 1, 1999 and the Change-in-Control Severance Agreement dated as of **[INSERT DATE OF PRIOR AGREEMENT]** by and between Williams and the Executive, but excluding The Williams Companies Retirement Restoration Plan and any agreements and plans awarding Stock Options and Restricted Shares. Each superseded agreement or understanding is void and of no further force and effect.

Article I.

Definitions

As used in this Agreement, the terms specified below shall have the following meanings:

1.1 "Accrued Annual Bonus" means the amount of any Annual Bonus earned but not yet paid as of the Termination Date, other than amounts Executive has elected to defer.

1.2 "Accrued Base Salary" means the amount of Executive's Base Salary that is accrued but not yet paid as of the Termination Date, other than amounts Executive has elected to defer.

1.3 "Accrued Obligations" means, as of the Termination Date, the sum of Executive's Accrued Base Salary, Accrued Annual Bonus, any accrued but unpaid Paid Time Off under Williams' Paid Time Off Program, and any other amounts and benefits which are then due to be paid or provided to Executive by Williams, but have not yet been paid or provided (as applicable), provided no payments will be accelerated if such acceleration would violate Code Section 409A.

1.4 "Affiliate" means any Person (including a Subsidiary) that directly or indirectly, through one or more intermediaries, controls, or is controlled by or is under common control with Williams. For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise.

1.5 "Agreement Date" — see the introductory paragraph of this Agreement.

1.6 "Agreement Term" means the period commencing on the Agreement Date and ending on the second anniversary of the Agreement Date or, if later, such later date to which the Agreement Term is extended under the following sentence, unless earlier terminated as provided herein. Commencing on the first anniversary of the Agreement Date, the Agreement Term shall automatically be extended each day by one day to create a new two-year term until, at any time after the first anniversary of the Agreement Date, Williams delivers written notice (an "Expiration Notice") to Executive that the Agreement shall expire on a date specified in the Expiration Notice (the 'Expiration Date") that is not less than 12 months after the date the Expiration Notice is delivered to Executive; provided, however, that if a Change Date occurs before the Expiration Date specified in the Expiration Notice, then such Expiration Notice shall be void and of no further effect. Notwithstanding anything herein to the contrary, with respect to a Post-Change Period, the Agreement Term shall end at the end of the Severance Period (as defined in Section 2.1(c)) if applicable, or if there is no such Severance Period, the earliest of the following: (a) the second anniversary of the Change Date, or (b) the Termination Date; provided that (i) the obligations, if any, of Williams to make payments under this Agreement due to a Separation from Service which occurred during the Agreement Term shall continue beyond the Agreement Term until all such obligations are fully satisfied, and (ii) the obligations of Executive under this Agreement shall continue beyond the Agreement Term until all such obligations are fully satisfied. Notwithstanding anything herein to the contrary, the Agreement shall automatically terminate upon the occurrence of a Disqualifying Disaggregation pursuant to Section 1.22(a).

1.7 "Annual Bonus" means the opportunity to receive payment of a cash annual incentive.

1.8 "Article" means an article of this Agreement.

1.9 "Base Salary" means annual base salary in effect on the Termination Date, disregarding any reduction that would qualify as Good Reason.

1.10 “Beneficial Owner” means such term as defined in Rule 13d-3 of the SEC under the Exchange Act.

1.11 “Beneficiary” — see Section 9.3.

1.12 “Board” means the Board of Directors of Williams or, from and after the Change Date that gives rise to a Surviving Corporation other than Williams, the Board of Directors of such Surviving Corporation.

1.13 “Cause” means any one or more of the following:

(a) Executive’s conviction of or plea of nolo contendere to a felony or other crime involving fraud, dishonesty or moral turpitude;

(b) Executive’s willful or reckless material misconduct in the performance of his duties which results in an adverse effect on Williams, the Subsidiary or an Affiliate;

(c) Executive’s willful or reckless violation or disregard of the code of business conduct;

(d) Executive’s material willful or reckless violation or disregard of a Williams or Subsidiary policy; or

(e) Executive’s habitual or gross neglect of duties;

provided, however, that for purposes of clauses (b) and (e), Cause shall not include any one or more of the following:

(i) bad judgment or negligence, other than Executive’s habitual neglect of duties or gross negligence;

(ii) any act or omission believed by Executive in good faith, after reasonable investigation, to have been in or not opposed to the interest of Williams, the Subsidiary or an Affiliate (without intent of Executive to gain, directly or indirectly, a profit to which Executive was not legally entitled);

(iii) any act or omission with respect to which a determination could properly have been made by the Board that Executive had satisfied the applicable standard of conduct for indemnification or reimbursement under Williams’ by-laws, any applicable indemnification agreement, or applicable law, in each case as in effect at the time of such act or omission; or

(iv) during a Post-Change Period, failure to meet performance goals, objectives or measures following good faith efforts to meet such goals, objectives or measures; and

further provided that, for purposes of clauses (b) through (e) if an act, or a failure to act, which was done, or omitted to be done, by Executive in good faith and with a reasonable belief, after reasonable investigation, that Executive's act, or failure to act, was in the best interests of Williams, the Subsidiary or an Affiliate or was required by applicable law or administrative regulation, such breach shall not constitute Cause if, within 10 business days after Executive is given written notice of such breach that specifically refers to this Section, Executive cures such breach to the fullest extent that it is curable. With respect to the above definition of "cause", no act or conduct by Executive will constitute "cause" if Executive acted: (i) in accordance with the instructions or advice of counsel representing Williams or there was a conflict such that Executive could not consult with counsel representing Williams other qualified counsel, or (ii) as required by legal process.

1.14 "Cause Determination" —see Section 2.2(b)(iv)

1.15 "Change Date" means the date on which a Change in Control first occurs during the Agreement Term.

1.16 "Change in Control" means, except as otherwise provided below, the occurrence of any one or more of the following during the Agreement Term:

(a) any person (as such term is used in Rule 13d-5 of the SEC under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than an Affiliate of Williams or any employee benefit plan (or any related trust) sponsored or maintained by Williams or any of its Affiliates (a "Related Party"), becomes the Beneficial Owner of 20% or more of the common stock of Williams or of Voting Securities representing 20% or more of the combined voting power of all Voting Securities of Williams, except that no Change in Control shall be deemed to have occurred solely by reason of such beneficial ownership by a Person (a "Similarly Owned Company") with respect to which both more than 75% of the common stock of such Person and Voting Securities representing more than 75% of the combined voting power of the Voting Securities of such Person are then owned, directly or indirectly, by the persons who were the direct or indirect owners of the common stock and Voting Securities of Williams immediately before such acquisition, in substantially the same proportions as their ownership, immediately before such acquisition, of the common stock and Voting Securities of Williams, as the case may be; or

(b) Williams Incumbent Directors (determined using the Agreement Date as the baseline date) cease for any reason to constitute at least a majority of the directors of Williams then serving; or

(c) consummation of a merger, reorganization, recapitalization, consolidation, or similar transaction (any of the foregoing, a 'Reorganization Transaction"), other than a Reorganization Transaction that results in the Persons who were the direct or indirect owners of the outstanding common stock and Voting Securities of Williams immediately before such Reorganization Transaction becoming, immediately after the consummation of such Reorganization Transaction, the direct or indirect owners, of both at least 65% of the then-outstanding common stock of the Surviving Corporation and Voting Securities representing at least 65% of the combined voting power of the then-outstanding Voting Securities of the Surviving Corporation, in substantially the same respective proportions as such Persons' ownership of the common stock and Voting Securities of Williams immediately before such Reorganization Transaction; or

(d) approval by the stockholders of Williams of a plan or agreement for the sale or other disposition of all or substantially all of the consolidated assets of Williams or a plan of complete liquidation of Williams, other than any such transaction that would result in (i) a Related Party owning or acquiring more than 50% of the assets owned by Williams immediately prior to the transaction or (ii) the Persons who were the direct or indirect owners of the outstanding common stock and Voting Securities of Williams immediately before such transaction becoming, immediately after the consummation of such transaction, the direct or indirect owners, of more than 50% of the assets owned by Williams immediately prior to the transaction.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to Executive if, in advance of such event, Executive agrees in writing that such event shall not constitute a Change in Control. Upon the Board's determination that a sale or other disposition of all or substantially all of the consolidated assets of Williams or a plan of complete liquidation of Williams that was approved by stockholders, as described in Section 1.16(d), will not occur, a Change in Control shall be deemed not to have occurred from such date of determination forward, and this Agreement shall continue in effect as if no Change in Control had occurred except to the extent termination requiring payments under this Agreement occurs prior to such Board determination.

1.17 "Code" means the Internal Revenue Code of 1986, as amended.

1.18 "Competitive Business" means, as of any date, any energy business and any individual or entity (and any branch, office, or operation thereof) which engages in, or proposes to engage in (with Executive's assistance) any of the following in which the Executive has been engaged in the twelve (12) months preceding the Termination Date (i) the harnessing, production, transmission, distribution, marketing or sale of oil, gas or other energy product or the transmission or distribution thereof through pipelines, wire or cable or similar medium (ii) any other business actively engaged in by Williams which represents for any calendar year or is projected by Williams (as reflected in a business plan adopted by Williams before Executive's Termination Date) to yield during any year during the first three-fiscal year period commencing on or after Executive's Termination Date, more than 5% of the gross revenue of Williams, and, in either case, which is located (x) anywhere in the United States, or (y) anywhere outside of the United States where Williams is then engaged in, or proposes as of the Termination Date to engage in to the knowledge of the Executive, any of such activities.

1.19 "Confidential Information" means any non-public information of any kind or nature in the possession of Williams or any of its Affiliates, including without limitation, ideas, processes, methods, designs, innovations, devices, inventions, discoveries, know-how, data, techniques, models, customer lists, marketing, business or strategic plans, financial information, research and development information, trade secrets or other subject matter relating to Williams' or its Affiliates' products, services, businesses, operations, employees, customers or suppliers, whether in tangible or intangible form, including (i) any information that gives Williams or any of its Affiliates a competitive advantage in the harnessing, production, transmission, distribution, marketing or sale of oil, gas or other energy or the transmission or distribution thereof through pipelines, wire or cable or similar medium or in the energy services or energy trading industry and other businesses in which Williams or an Affiliate is engaged, or (ii) any information obtained by Williams or any of its Affiliates from third parties to which Williams or an Affiliate owes a duty of confidentiality, or (iii) any information that was learned, discovered, developed, conceived, originated or prepared during or as a result of Executive's performance of any services on behalf of Williams or any Affiliate. Notwithstanding the foregoing, "Confidential Information" shall not include: (i) information that is or becomes generally known to the public through no fault of Executive; (ii) information obtained on a non-confidential basis from a third party other than Williams or any Affiliate, which third party disclosed such information without breaching any legal, contractual or fiduciary obligation; or (iii) information approved for release by written authorization of Williams.

1.20 "Consummation Date" means the date on which a Reorganization transaction is consummated.

1.21 "Disability" means any medically determinable physical or mental impairment of Executive where he or she (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months, receiving income replacement benefits for a period of not less than three (3) months under an accident and health plan covering employees of Executive's employer. Notwithstanding the forgoing, all determinations of whether an Executive is Disabled shall be made in accordance with Section 409A of the Code.

1.22 "Disqualifying Disaggregation" means

(a) The cessation of Executive's employment with Williams and/or its Affiliates prior to the Change Date for any reason, including but not limited to a cessation of employment with Williams and/or its Affiliates which is effected by a sale, spin-off, or other disaggregation ("Disaggregation") by Williams or an Affiliate of the business unit (including, but not limited to, a sale, spin-off or other disaggregation of a Subsidiary) which employed Executive immediately prior to such Disaggregation; or

(b) The cessation of Executive's employment with Williams and/or its Affiliates during the Post-Change Period due to a Disaggregation solely where Executive is employed by the successor in substantially the same position as the position held prior to the Disaggregation, provided the successor assumes all of Williams' obligations under this Agreement.

1.23 "Employer" means Williams or, if Executive is not employed directly by Williams, the Subsidiary that from time to time employs Executive on or after the Agreement Date, and the successor of either (provided, in the case of a Subsidiary, that such successor is also a Subsidiary).

1.24 "ERISA" means the Employee Retirement Income security Act of 1974, as amended.

1.25 "Exchange Act" means the Securities Exchange Act of 1934, as amended.

1.26 "Good Reason" means a Separation from Service by Executive in accordance with the substantive and procedural provisions of this Section.

(a) Separation from Service by Executive for "Good Reason" means a Separation from Service initiated by Executive on account of any one or more of the following actions or omissions that, unless otherwise specified, occurs during a Post-Change Period:

(i) a material adverse reduction in the nature or scope of Executive's office, position, duties, functions, responsibilities or authority (including reporting responsibilities and authority) during a Post-Change Period from the most significant of those held, exercised and assigned at any time during the 90-day period immediately before the Change Date;

(ii) any reduction in or failure to pay Executive's annual Base Salary at an annual rate not less than 12 times the highest monthly base salary paid or payable to Executive by his Employer in respect of the 12-month period immediately before the Change Date;

(iii) any reduction in the Target Annual Bonus which Executive may earn determined as of the Change Date or failure to pay Executive's Annual Bonus on terms substantially equivalent to those provided to peer executives of the Employer;

(iv) a material reduction of Executive's aggregate compensation and/or aggregate benefits from the amounts and/or levels in effect on the Change Date, unless such reduction is part of a policy applicable to peer executives of the Employer and of any successor entity;

(v) required relocation during a Post-Change Period of more than 50 miles of (A) Executive's workplace, or (B) the principal offices of the Employer or its successor (if such offices are Executive's workplace), in each case without the consent of Executive; provided, however, in both cases of (A) and (B) of this subsection (v), such new location is farther from Executive's residence than the prior location;

(vi) the failure at any time of a successor to Executive's Employer explicitly to assume and agree to be bound by this Agreement; or

(vii) the giving of a Notice of Consideration pursuant to Section 2.2(b)(ii) and the subsequent failure to terminate Executive for Cause and within a period of 90 days thereafter in compliance with all of the substantive and procedural requirements of Section 2.2.

(b) Notwithstanding anything in this Agreement to the contrary, no act or omission shall constitute grounds for "Good Reason":

(i) Unless Executive gives a Notice of Termination to Williams and the Employer 30 days prior to his intent to terminate his employment for Good Reason which describes the alleged act or omission giving rise to Good Reason; and

(ii) Unless such Notice of Termination is given within 90 days of Executive's first actual knowledge of such act or omission; and

(iii) Unless Williams or the Employer fails to cure such act or omission within the 30 day period after receiving the Notice of Termination.

(c) No act or omission shall constitute grounds for "Good Reason", if Executive has consented in writing to such act or omission in a document that makes specific reference to this Section.

1.27 "Gross-Up Payment" — see Section 3.1.

1.28 "including" means including without limitation.

1.29 "IRS" means the Internal Revenue Service of the United States of America.

1.30 "Legal and Other Expenses" — see Section 4.1.

1.31 "Notice of Consideration" — see Section 2.2(b)(ii).

1.32 "Notice of Termination" means a written notice of a Separation from Service, if applicable, given in accordance with Section 9.7 that sets forth (a) the specific termination provision in this Agreement relied on by the party giving such notice, (b) in reasonable detail the specific facts and circumstances claimed to provide a basis for such Separation from Service, and (c) if the Termination Date is other than the date of receipt of such Notice of Termination, the Termination Date.

1.33 "Person" means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

1.34 "Post-Change Period" means the period commencing on the Change Date and ending on the earlier of the Termination Date or the second anniversary of the Change Date.

1.35 "Potential Parachute Payment" — see Section 3.1.

1.36 "Pro-rata Annual Bonus" means, in respect of an Employer's fiscal year during which the Termination Date occurs, an amount equal to the product of Executive's Target Annual Bonus (determined as of the Termination Date) multiplied by a fraction, the numerator of which equals the number of days from and including the first day of such fiscal year through and including the Termination Date, and the denominator of which equals 365.

1.37 "Reorganization Transaction" — see clause (c) of the definition of "Change in Control".

1.38 "Restricted Shares" means shares of restricted stock, restricted stock units, deferred stock or similar awards.

1.39 "SEC" means the United States Securities and Exchange Commission.

1.40 "Section" means, unless the context otherwise requires, a section of this Agreement.

1.41 "Separation from Service" means an Executive's termination or deemed termination from employment with Williams and its Subsidiaries. For purposes of determining whether a Separation from Service has occurred, the employment relationship is treated as continuing intact while the Executive is on military leave, sick leave or other bona fide leave of absence if the period of such leave does not exceed six (6) months, or if longer, so long as the Executive retains a right to reemployment with his or her employer under an applicable statute or by contract. For this purpose, a leave of absence constitutes a bona fide leave of absence only if there is a reasonable expectation that the Executive will return to perform services for his or her employer. If the period of leave exceeds six (6) months and the Executive does not retain a right to reemployment under an applicable statute or by contract, the employment relationship will be deemed to terminate on the first date immediately following such six (6) month period. Notwithstanding the foregoing, if a leave of absence is due to any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than six (6) months, and such impairment causes the Executive to be unable to perform the duties of the Executive's position of employment or any substantially similar position of employment, a twenty-nine (29) month period of absence shall be substituted for such six (6) month period. For purposes of this Agreement, a Separation from Service occurs at the date as of which the facts and circumstances indicate either that, after such date: (A) the Executive and Williams reasonably anticipate the Executive will perform no further services for Williams and its Subsidiaries (whether as an employee or an independent contractor or (B) that the level of bona fide services the Executive will perform for Williams and its Affiliates (whether as an employee or independent contractor) will permanently decrease to no more than twenty (20%) of the average level of bona fide services performed over the immediately preceding thirty-six (36) month period or, if the Executive has been providing services to Williams and its Subsidiaries for less than thirty-six (36) months, the full period over which the Executive has rendered services, whether as an employee or independent contractor. The determination of whether a Separation from Service has occurred shall be governed by the provisions of Treasury Regulation § 1.409A-1, as amended, taking into account the objective facts and circumstances with respect to the level of bona fide services performed by the Executive after a certain date.

1.42 "Stock Options" means stock options, stock appreciation rights or similar awards.

1.43 “Subsidiary” means a corporation, trade or business, if it and The Williams Companies, Inc. are members of a controlled group of corporations as defined in Code Section 414(b) or under common control as defined under Code Section 414(c); the standard of control under Code Sections 414(b) and 414(c) shall be deemed to be “at least 80%” and all determinations shall be made in accordance with Code Section 409A and the applicable guidance thereunder.

1.44 “Surviving Corporation” means the parent corporation resulting from a Reorganization Transaction or, if securities representing at least 50% of the aggregate voting power of all Voting Securities of a corporation effected by a Change in Control which is not a Reorganization Transaction are directly or indirectly owned by another corporation, such other corporation.

1.45 “Target Annual Bonus” means, as of any date, the amount equal to the product of Executive’s Base Salary determined as of such date multiplied by the percentage of such Base Salary to which Executive would have been entitled immediately prior to such date under any Annual Bonus arrangement for the fiscal year for which the Annual Bonus is awarded if the performance goals established pursuant to such Annual Bonus were achieved at the 100% level as of the end of the fiscal year; provided, however, that if Executive’s Annual Bonus is discretionary and no 100% target level is formally established either under the Annual Bonus arrangement or otherwise, Executive’s “Target Annual Bonus” shall mean the amount equal to the 100% of Executive’s Base Salary.

1.46 “Taxes” means federal, state, local and other income, employment and other taxes.

1.47 “Termination Date” means the date of the receipt of the Notice of Termination by Executive (if such notice is given by Executive’s Employer) or by Executive’s Employer (if such notice is given by Executive), or any later date, not more than 30 days after the giving of such notice, specified in such notice; provided, however, that:

(a) Executive’s employment is terminated by reason of death or Disability, the Termination Date shall be the date of Executive’s death or the date of deemed termination of employment due to Disability, as applicable, regardless of whether a Notice of Termination has been given; and

(b) if no Notice of Termination is given, the Termination Date shall be the last date on which Executive is employed by an Employer; and

(c) for purposes of Article VI (Restrictive Covenants) if the Executive does not have a Separation from Service, the Termination Date shall be the later of the date the entity that employs Executive ceases to be a Subsidiary, or, after a Disaggregation (as defined in Section 1.22), the date Executive’s employment with the successor business unit terminates, whether such termination is initiated by such successor or by Executive.

1.48 “Voting Securities” of a corporation means securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

1.49 "Williams" — see the introductory paragraph of this Agreement.

1.50 "Williams Incumbent Directors" means, determined as of any date by reference to any baseline date:

(a) the members of the Board on the date of such determination who have been members of the Board since such baseline date, and

(b) the members of the Board on the date of such determination who were appointed or elected after such baseline date and whose election, or nomination for election by stockholders of Williams or the Surviving Corporation, as applicable, was approved by a vote or written consent of two-thirds of the directors comprising the Williams Incumbent Directors on the date of such vote or written consent, but excluding each such member whose initial assumption of office was in connection with (i) an actual or threatened election contest, including a consent solicitation, relating to the election or removal of one or more members of the Board, (ii) a "tender offer" (as such term is used in Section 14(d) of the Exchange Act), or (iii) a proposed Reorganization Transaction.

1.51 "Williams Parties" means Williams and Executive's Employer.

1.52 "Work Product" means any and all work product, including, but not limited to, documentation, tools, templates, processes, procedures, discoveries, inventions, innovations, technical data, concepts, know-how, methodologies, methods, drawings, prototypes, trade secrets, notebooks, reports, findings, business plans, recommendations and memoranda of every description, that Executive makes, conceives, discovers or develops alone or with others during the course of Executive's employment with Williams or during the one year period following Executive's Termination Date (whether or not protectable upon application by copyright, patent, trademark, trade secret or other proprietary rights).

Article II.

Williams' Obligations Upon Separation from Service

2.1 If By Executive for Good Reason or By an Employer Other Than for Cause, Disability, Death or Disqualifying Disaggregation. If Executive has a Separation from Service for Good Reason or there is an Employer-initiated Separation from Service of the Executive for any reason other than Cause, Disability, Death or a Disqualifying Disaggregation during the Post-Change Period, then in addition to payment of all Accrued Obligations, which shall be payable no later than ten (10) business days after the Termination Date, Williams' and the Employer's sole obligations to Executive under this Article II shall be as follows:

(a) Severance Payments. Executive shall be paid a lump-sum cash amount equal to the sum of the following, on the first business day following six (6) months after Executive's Separation from Service:

(i) Prorated Annual Bonus for Year of Termination. Executive's Pro-rata Annual Bonus reduced (but not below zero) by the amount of any Annual

Bonus paid to Executive with respect to the Employer's fiscal year during which the Termination Date occurs;

(ii) Retirement Enhancements. The sum of:

(A) an amount equal to the sum of the value of the unvested portion of Executive's accounts or accrued benefits under any defined contribution plan qualified under Section 401(a) of the Code maintained by the Williams Parties as of the Termination Date and forfeited by Executive due to Separation from Service; and

(B) an amount equal to three (3) times the total of the allocations made by Williams for Executive under The Williams Companies Retirement Restoration Plan (or any successor plan) during the calendar year preceding the calendar year in which the Change Date occurs.

(iii) Multiple of Salary and Bonus. An amount equal to three (3) times the sum of (A) Base Salary plus (B) the Target Annual Bonus, each determined as of the Termination Date; provided, however, that any reduction in Executive's Base Salary or Target Annual Bonus that would qualify as Good Reason shall be disregarded for this purpose.

(b) Stock Incentive Awards. To the extent provided in the applicable award agreements and the applicable plan, all of Executive's Stock Options then outstanding shall immediately become fully vested and remain exercisable until the 18-month anniversary of the Termination Date (or such later date as may be set forth in the applicable award agreement, including, but not limited to, a later exercise date under an award agreement if Executive has met the age and service requirements for retirement) or, if earlier, the option expiration date for any such Stock Option. All of Executive's Restricted Shares then outstanding shall only vest and payout in accordance with the applicable award agreements for such Restricted Shares.

(c) Continuation of Welfare Benefits. During the lesser of the period during which Executive or a qualifying beneficiary (as defined in Section 607 of the Employee Retirement Income Security Act of 1974, as amended) has in effect an election for post-termination continuation coverage or conversion rights to welfare benefits under applicable law, including Section 4980 of the Code ("COBRA"), or the period ending on the 18-month anniversary of the Termination Date ("Severance Period"), Executive (or, if applicable, the qualifying beneficiary) shall be entitled to such coverage at an out-of-pocket premium cost that does not exceed the out-of-pocket premium cost applicable to similarly situated active employees (and their eligible dependents); provided, however, that if Executive is eligible to retiree benefits provided under any welfare benefit plan, program, policy, practice or procedure of the Williams Parties, Executive shall be entitled to receive such retiree benefits in lieu of the COBRA coverage provided by this Section 2.1(c).

(d) Outplacement. Executive shall be reimbursed for reasonable fees and costs for outplacement services incurred by Executive within six (6) months after the Separation from Service, promptly upon presentation of reasonable documentation of such fees and costs, subject to a maximum of $25,000. All requests of Executive for reimbursement must be submitted to Williams within one (1) year of Separation from Service and Williams shall make the reimbursement of reasonable requests no later than thirty (30) days after such request, but in all events within fifteen (15) months of Separation from Service.

(e) Indemnification. Executive shall be indemnified and held harmless by Williams and the Employer on the same terms as other peer executives and to the greatest extent permitted under applicable law as the same now exists or may hereafter be amended and the Employer's and Williams' by-laws as such exist on the Agreement Date, or such greater rights that may be provided by amendment to such by-laws from time to time, if Executive was, is, or is threatened to be, made a party to any pending, completed or threatened action, suit, arbitration, alternate dispute resolution mechanism, investigation, administrative hearing or any other proceeding whether civil, criminal, administrative or investigative, and whether formal or informal, by reason of the fact that Executive is or was, or had agreed to become, a director, officer, employee, agent or fiduciary of the Employer or any other entity which Executive is or was serving at the request of the Employer or Williams ("Proceeding"), against all expenses (including reasonable attorneys' fees) and all claims, damages, liabilities and losses incurred or suffered by Executive or to which Executive may become subject for any reason, and (ii) shall be entitled to advancement of any such indemnifiable expenses in accordance with the Employer's and Williams' by-laws as such exist on the Agreement Date, or such greater rights that may be provided by amendment to such by-laws from time to time. A Proceeding shall not include any proceeding to the extent it concerns or relates to a matter described in Section 4.1 (concerning reimbursement of certain costs and expenses).

(f) Directors' and Officers' Liability Insurance. For a period of six years after the Termination Date (or for any known longer applicable statute of limitations period), the Executive shall be entitled to coverage under a directors' and officers' liability insurance policy in an amount no less than, and on the same terms as those provided to peer executive officers and directors of the Employer.

2.2 If by the Employer for Cause.

(a) Termination for Cause. If the Executive has a Separation from Service for Cause during the Post-Change Period, the Williams Parties' sole obligation to Executive under this Article II shall be to pay Executive a lump-sum cash amount equal to all Accrued Obligations determined as of the Termination Date.

(b) Change in Control: Procedural Requirements for Termination for Cause. For any Separation from Service for Cause during any part of a Post-Change Period, the Williams Parties shall strictly observe each of the following substantive and procedural provisions:

(i) The Board shall call a meeting for the stated purpose of determining whether Executive's acts or omissions satisfy the requirements of the definition of "Cause" and, if so, whether to terminate Executive's employment for Cause.

(ii) Not less than 15 days prior to the date of such meeting, the Board shall provide or cause to be provided Executive and each member of the Board written notice (a "Notice of Consideration") of (A) a detailed description of the acts or omissions alleged to constitute Cause, (B) the date of such meeting of the Board, and (C) Executive's rights under clauses (iii) and (iv) below.

(iii) Executive shall have the opportunity to appear before the Board in person and, at Executive's option, with legal counsel, and/or present to the Board a written response to the Notice of Consideration.

(iv) Executive's employment may be terminated for Cause only if (A) the acts or omissions specified in the Notice of Consideration did in fact occur and such actions or omissions do constitute Cause as defined in this Agreement, (B) the Board, by affirmative vote of at least 66 2/3 of its members (excluding Executive's vote), makes a specific determination to such effect and to the effect that Executive's employment should be terminated for Cause ("Cause Determination"), and (C) Williams thereafter provides Executive with a Notice of Termination that specifies in specific detail the basis of such Separation from Service for Cause and which Notice shall be consistent with the reasons set forth in the Notice of Consideration.

Nothing in this Section 2.2(b) shall preclude the Board, by majority vote, from suspending Executive from his duties, with pay, at any time.

(c) Change in Control: Standard of Review. In the event that the existence of Cause during a Post-Change Period shall become an issue in any action or proceeding between Executive, on the one hand, and any one or more of the Williams Parties on the other hand, the Williams Parties, as applicable, shall, notwithstanding the Cause Determination, have the burden of establishing that the actions or omissions specified in the Notice of Consideration did in fact occur and do constitute Cause and that the Williams Parties have satisfied all applicable substantive and procedural requirements of this Section.

2.3 If by Executive Other Than for Good Reason. If Executive has a Separation from Service initiated by the Executive during the Post-Change Period other than for Good Reason, Disability or death, the sole obligation of the Williams Parties to Executive under this Article II shall be to pay Executive a lump-sum cash amount equal to all Accrued Obligations determined as of the Termination Date.

2.4 If by Death or Disability. If Executive dies during the Post-Change Period or if Executive has a Separation from Service during the Post-Change Period by reason of Executive's Disability, the Williams Parties' sole obligation to Executive under this Article II shall be to pay

Executive a lump-sum cash amount equal to all Accrued Obligations determined as of the Termination Date.

2.5 Waiver and Release. Notwithstanding anything herein to the contrary, in the event that Executive's employment terminates pursuant to Section 2.1, no Williams Party shall have any obligation to Executive under Section 2.1(a) Sections 2.1(c)-(f) and Article III unless and until Executive executes and delivers to Williams within sixty (60) days after Separation from Service a release and waiver of Williams, the Employer and Affiliates, in substantially the same form as attached hereto as Exhibit A, or as otherwise mutually acceptable.

2.6 Breach of Covenants. If a court determines that Executive has breached any non-competition, non-solicitation, non-disparagement, confidential information or intellectual property covenant entered into at any time between Executive (on the one hand) and Williams, the Employer, or any Affiliate (on the other hand), including the Restrictive Covenants in Article VI, (a) no Williams Party shall have any obligation to pay or provide any severance or benefits under Articles II and/or III, (b) all of Executive's unexercised Stock Options shall terminate as of the date of the breach, (c) all of Executive's Restricted Stock shall be forfeited as of the date of the breach, (d) Executive shall reimburse a Williams Party for any amount already paid under Articles II and/or III, and (e) Executive shall repay to Williams an amount equal to the aggregate "spread" (as defined below) on all Stock Options exercised in the one year period prior to the first date on which Executive breached any such covenant ("Breach Date"). For purposes of this Section 2.6, "spread" in respect of any Stock Option shall mean the product of the number of shares as to which such Stock Option has been exercised during the one year period prior to the Breach Date multiplied by the difference between the closing price of the common stock on the exercise date (or if the common stock did not trade on the New York Stock Exchange or other exchange, if any, on which common stock had a higher trading volume at the time, on the exercise date, the most recent date on which the common stock did so trade) and the exercise price of the Stock Options.

Article III.

Certain Additional Payments by Williams

3.1 Gross-Up Payment. If at any time or from time to time, it shall be determined by independent auditors selected by Williams that any payment or other benefit to Executive pursuant to Article II of this Agreement or otherwise ("Potential Parachute Payment") is or will become subject to the excise tax imposed by Section 4999 of the Code or any similar tax payable under any state, local, foreign or other law, but expressly excluding any income taxes and penalties imposed pursuant to Section 409A of the Code ("Excise Taxes"), then the Employer shall, pursuant to Section 3.2, pay or cause to be paid a tax gross-up payment ("Gross-Up Payment").

3.2 Gross-Up Payment. The Gross-Up Payment shall be an amount equal to the product of

(a) The amount of the Excise Taxes,

multiplied by

(b) A fraction (the 'Gross-Up Multiple"), the numerator of which is one (1.0), and the denominator of which is one (1.0) minus the lesser of (i) the sum, expressed as a decimal fraction, of the effective marginal rates of any Taxes and any Excise Taxes applicable to the Gross-Up Payment or (ii) .80, it being intended that the Gross-Up Multiple shall in no event exceed five (5.0). If different rates of tax are applicable to various portions of a Gross-Up Payment, the weighted average of such rates shall be used.

The Gross-Up Payment is intended to compensate Executive for all Excise Taxes and any other Taxes payable by Executive hereunder. The Employer shall pay, or cause to be paid, the Gross-Up Payment to Executive within thirty (30) days of the calculation of such amount subject to six months' delay following Executive's Separation from Service if such delay would be required by Code Section 409A, in order to avoid adverse consequences under Code Section 409A, based upon the assumption that Executive is a key employee as defined in Code Section 409A(a)(2)(B)(i). In all events, any Gross-Up Payment shall be paid to Executive no later than the last day of the calendar year next following the year in which the related taxes are remitted to the applicable taxing authority.

3.3 Limitations on Gross-Up Payments. To the extent possible, any payments or other benefits to Executive pursuant to Article II of the Agreement shall be allocated as consideration for restrictive covenants applicable to Executive.

3.4 Additional Gross-up Amounts. If, for any reason, the Employer's independent auditors later determine that the amount of Excise Taxes payable by Executive is greater than the amount initially determined pursuant to Section 3.2, then the Employer shall, subject to Section 3.3 and 3.5, pay Executive, within thirty (30) days of such determination, or pay to the IRS as required by applicable law, an amount (which shall also be deemed a Gross-Up Payment) equal to the product of:

(a) the sum of (i) such additional Excise Taxes and (ii) any interest, penalties, expenses or other costs incurred by Executive as a result of having taken a position in accordance with a determination made pursuant to Sections 3.2 or 3.5,

multiplied by

(b) the Gross-Up Multiple.

3.5 Amount Increased or Contested.

(a) Executive shall notify all Williams Parties in writing (an "Executive's Notice") of any claim by the IRS or other taxing authority (an "IRS Claim") that, if successful, would require the payment by Executive of Excise Taxes in respect of Potential Parachute Payments in an amount in excess of the amount of such Excise Taxes determined in accordance with Section 3.2. Executive's Notice shall include the nature and amount of such IRS Claim, the date on which such IRS Claim is due to be paid (the "IRS Claim Deadline"), and a copy of all notices and other documents or correspondence received by Executive in respect of such IRS Claim. Executive shall give Executive's Notice as soon as practicable, but no later than the earlier of (i) 10 days after Executive first obtains actual knowledge of such IRS Claim or (ii) five business days before the IRS Claim Deadline; provided, however, that any failure to give Executive's Notice shall affect the Williams Parties' obligations under this Article only to the extent that a Williams Party is actually prejudiced by such failure. If at least one business day before the IRS Claim Deadline the Employer shall:

(i) deliver to Executive a written certificate from the Employer's independent auditors ("Company Certificate") to the effect that, notwithstanding the IRS Claim, the amount of Excise Taxes, interest or penalties payable by Executive is either zero or an amount less than the amount specified in the IRS Claim,

(ii) pay to Executive, or to the IRS as required by applicable law, an amount (which shall also be deemed a Gross-Up Payment) equal to difference between the product of (A) amount of Excise Taxes, interest and penalties specified in the Company Certificate, if any, multiplied by (B) the Gross-Up Multiple, less the portion of such product, if any, previously paid to Executive by the Employer, and

(iii) direct Executive pursuant to Section 3.5(d) to contest the balance of the IRS Claim,

then Executive shall pay only the amount, if any, of Excise Taxes, interest and penalties specified in the Company Certificate. In no event shall Executive pay an IRS Claim earlier than 30 business days after having given Executive's Notice (or, if sooner, the IRS Claim Deadline).

(b) At any time after the payment by Executive of any amount of Excise Taxes, other Taxes or related interest or penalties in respect of Potential Parachute Payments (including any such amount equal to or less than the amount of such Excise Taxes specified in any Company Certificate, or IRS Claim), any Williams Party may in its discretion require Executive to pursue a claim for a refund (a "Refund Claim") of all or any portion of such Excise Taxes, other Taxes, interest or penalties as may be specified by the Williams Party in a written notice to Executive.

(c) If a Williams Party notifies Executive in writing that a Williams Party desires Executive to contest an IRS Claim or to pursue a Refund Claim, Executive shall:

(i) give the Williams Party all information that it reasonably requests in writing from time to time relating to such IRS Claim or Refund Claim, as applicable,

(ii) take such action in connection with such IRS Claim or Refund Claim (as applicable) as the Williams Party reasonably requests in writing from time to time, including accepting legal representation with respect thereto by an attorney selected by the Williams Party, subject to the approval of Executive (which approval shall not be unreasonably withheld or delayed),

(iii) cooperate with the Williams Party in good faith to contest such IRS Claim or pursue such Refund Claim, as applicable,

(iv) permit the Williams Party to participate in any proceedings relating to such IRS Claim or Refund Claim, as applicable, and

(v) contest such IRS Claim or prosecute Refund Claim (as applicable) to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Williams Party may from time to time determine in its discretion.

The Williams Party shall control all proceedings in connection with such IRS Claim or Refund Claim (as applicable) and in its discretion may cause Executive to pursue or forego any and all administrative appeals, proceedings, hearings and conferences with the Internal Revenue Service or other taxing authority in respect of such IRS Claim or Refund Claim (as applicable); provided that (A) any extension of the statute of limitations relating to payment of taxes for the taxable year of Executive relating to the IRS Claim is limited solely to such IRS Claim, (B) the Williams Party's control of the IRS Claim or Refund Claim (as applicable) shall be limited to issues with respect to which a Gross-Up Payment would be payable, and (C) Executive shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or other taxing authority.

(d) Any Williams Party may at any time in its discretion direct Executive to (i) contest the IRS Claim in any lawful manner or (ii) pay the amount specified in an IRS Claim and pursue a Refund Claim; provided, however, that if a Williams Party directs Executive to pay an IRS Claim and pursue a Refund Claim, the Williams Party shall advance the amount of such payment to Executive on an interest-free basis and shall indemnify Executive, on an after-tax basis, for any Excise Tax or income tax, including related interest or penalties, imposed with respect to such advance.

(e) The Williams Party shall pay directly all legal, accounting and other costs and expenses (including additional interest and penalties) incurred by the Williams Party or Executive in connection with any IRS Claim or Refund Claim, as applicable, and shall indemnify Executive, on an after-tax basis, for any Excise Tax or income tax, including related interest and penalties, imposed as a result of such payment of costs and expenses. Any payment or reimbursement of any expenses incurred by Executive in connection with any IRS Claim or Refund Claim to which Executive may be entitled pursuant to this Section 3.5 shall be paid or reimbursed as soon as practicable after presentation of Executive's written request for reimbursement accompanied by evidence that such costs or expenses were incurred. In any event, any Gross-Up Payment will be made no later than the last day of the calendar year next following the calendar year in which Executive remits the related taxes, and any required reimbursement of expenses incurred due to a tax audit or litigation addressing the existence or amount of a tax liability will be made by the end of the calendar year next following the calendar year in which the taxes that are the subject of the audit or litigation are remitted to the taxing authority, or where as a result of such audit or litigation no taxes are remitted, the end of the calendar year next following the calendar year in which such audit is completed or there is a final and nonappealable settlement or other resolution of the litigation. Notwithstanding the foregoing, such payments will be subject to six months' delay following Executive's Separation from Service if such delay would be required by Code Section 409A, in order to avoid adverse consequences under Code Section 409A, based upon the assumption that Executive is a key employee as defined in Code Section 409A(a)(2)(B)(i).

3.6 Refunds. If, after the receipt by Executive or the IRS of any payment or advance of Excise Taxes or other Taxes by any Williams Party, Executive receives any refund with respect to such Excise Taxes, Executive shall (subject to the Employer complying with any applicable requirements of Section 3.5) promptly pay the Williams Party which paid the Gross-Up Payment the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto). If, after the receipt by Executive of an amount advanced by any Williams Party pursuant to Section 3.5 or receipt by the IRS of an amount paid by a Williams Party on behalf of Executive pursuant to Section 3.5, a determination is made that Executive shall not be entitled to any refund with respect to such claim and a Williams Party does not notify Executive in writing of its intent to contest such determination within 30 days after the Williams Parties receive written notice of such determination, then such advance shall be forgiven and shall not be required to be repaid and the amount of such advance shall offset, to the extent thereof, the amount of Gross-Up Payment required to be paid. Any contest of a denial of refund shall be controlled by Section 3.5(d).

Article IV.

Expenses and Interest

4.1 Legal and Other Expenses.

(a) If Executive incurs legal fees or other expenses (including expert witness and accounting fees) in an effort to determine, secure, preserve, establish entitlement to, or obtain benefits under this Agreement (collectively, "Legal and Other Expenses"), Executive shall, regardless of the outcome of such effort, be entitled to payment of or reimbursement for such Legal and Other Expenses in accordance with Section 4.1(b).

(b) All Legal and Other Expenses shall be paid or reimbursed on a monthly basis within 10 days after presentation of Executive's written request for reimbursement accompanied by evidence that such Legal and Other Expenses were incurred. In all events, the Company shall pay or reimburse such eligible expenses in accordance with the requirements of Treasury Regulation § 1.409A-3(i)(1)(iv) for reimbursement and in-kind benefit plans, to the extent applicable. For this purpose, (i) any reimbursement shall be for expenses incurred during Executive's lifetime or within two additional years following Executive's death, (ii) the amount of expenses eligible for reimbursement, or benefits provided, in one calendar year shall not affect the expenses eligible for reimbursement, or benefits to be provided, in any other calendar year, (iii) the reimbursement of any eligible expense will be made no later than the last day of the calendar year next following the calendar year in which the expense was incurred, and (iv) the right to any reimbursement or benefit shall not be subject to liquidation or exchange for any other benefit.

(c) If Executive does not prevail (after exhaustion of all available judicial remedies) in respect of a claim by Executive or by one or more of the Williams Parties, hereunder, and such parties establish before a court of competent jurisdiction that Executive had no reasonable basis for his claim hereunder, or for his response to such parties' claim hereunder, or acted in bad faith, no further payment of or reimbursement for Legal and Other Expenses shall be due to Executive in respect of such claim and Executive shall refund any amounts previously paid or reimbursed hereunder with respect to such claim.

4.2 Interest. If an amount due is not paid to Executive under this Agreement within five business days after such amount first became due and owing, interest shall accrue on such amount from the date it became due and owing until the date of payment at a annual rate equal to 200 basis points above the base commercial lending rate published in *The Wall Street Journal* in effect from time to time during the period of such nonpayment.

Article V.

No Set-off or Mitigation

5.1 No Set-off by Williams. Executive's right to receive when due the payments and other benefits provided for under this Agreement is absolute, unconditional and subject to no setoff, counterclaim, recoupment, or other claim, right or action that any Williams Party may have against Executive or others, except as expressly provided in this Section. Notwithstanding the prior sentence, any Williams Party shall have the right to deduct any amounts outstanding on any loans or other extensions of credit to Executive from a Williams Party from Executive's payments and other benefits (if any) provided for under this Agreement. Time is of the essence in the performance by the Williams Parties of their respective obligations under this Agreement.

5.2 No Mitigation. Executive shall not have any duty to mitigate the amounts payable by any Williams Party under this Agreement by seeking new employment or self-employment following termination. Except as specifically otherwise provided in this Agreement, all amounts payable pursuant to this Agreement shall be paid without reduction regardless of any amounts of salary, compensation or other amounts which may be paid or payable to Executive as the result of Executive's employment by another employer or self-employment.

Article VI.

Restrictive Covenants

6.1 Confidential Information. The Executive acknowledges that in the course of performing services for Williams and its Affiliates, Executive may create (alone or with others), learn of, have access to, or receive Confidential Information. The Executive recognizes that all such Confidential Information is the sole and exclusive property of Williams and its Affiliates or of third parties to which Williams or an Affiliate owes a duty of confidentiality, that it is Williams' policy to safeguard and keep confidential all such Confidential Information, and that disclosure of Confidential Information to an unauthorized third party would cause irreparable damage to Williams and its Affiliates. Executive agrees that, except as required by the duties of Executive's employment with Williams or any of its Affiliates and except in connection with enforcing Executive's rights under this Agreement or if compelled by a court or governmental agency, in each case provided that prior written notice is given to Williams, Executive will not, without the written consent of Williams, willfully disseminate or otherwise disclose, directly or indirectly, any Confidential Information disclosed to Executive or otherwise obtained by Executive during his employment with Williams or its Affiliates, and will take all necessary precautions to prevent disclosure, to any unauthorized individual or entity (whether or not such individual or entity is employed or engaged by, or is otherwise affiliated with, Williams or any Affiliate), and will use the Confidential Information solely for the benefit of Williams and its Affiliates and will not use the Confidential Information for the benefit of any other Person nor permit its use for the benefit of Executive. These obligations shall continue during and after the termination of Executive's employment for any reason and for so long as the Confidential Information remains Confidential Information.

6.2 Non-Competition. During the period beginning on the Agreement Date and ending on the first anniversary of the Termination Date, regardless of the reason for Executive's Separation from Service, Executive agrees that without the written consent of Williams Executive shall not at any time, directly or indirectly, in any capacity:

(a) engage or participate in, become employed by, serve as a director of, or render advisory or consulting or other services in connection with, any Competitive Business; provided, however, that after Executive's Separation from Service, this Section 6.2 shall not preclude Executive from (i) being an employee of, or consultant to, any business unit of a Competitive Business if (A) such business unit does not qualify as a Competitive Business in its own right and (B) Executive does not have any direct or indirect involvement in, or responsibility for, any operations of such Competitive Business that cause it to qualify as a Competitive Business, or (ii) with the approval of Williams, being a consultant to, an advisor to, a director of, or an employee of a Competitive Business; or

(b) make or retain any financial investment, whether in the form of equity or debt, or own any interest, in any Competitive Business. Nothing in this subsection (b) shall, however, restrict Executive from making an investment in any Competitive Business if such investment does not (i) represent more than 1% of the aggregate market value of the outstanding capital stock or debt (as applicable) of such Competitive

Business, (ii) give Executive any right or ability, directly or indirectly, to control or influence the policy decisions or management of such Competitive Business, or (iii) create a conflict of interest between Executive's duties to Williams and its Affiliates or under this Agreement and his interest in such investment.

6.3 Non-Solicitation. During the period beginning on the Agreement Date and ending on the first anniversary of the Termination Date, regardless of the reason for Executive's Separation from Service, Executive shall not, directly or indirectly:

(a) other than in connection with the good-faith performance of his duties as an officer of Williams or its Affiliates, cause or attempt to cause any employee, director or consultant of Williams or an Affiliate to terminate his or her relationship with Williams or an Affiliate;

(b) employ, engage as a consultant or adviser, or solicit the employment or engagement as a consultant or adviser, of any employee of Williams or an Affiliate (other than by Williams or its Affiliates), or cause or attempt to cause any Person to do any of the foregoing;

(c) establish (or take preliminary steps to establish) a business with, or cause or attempt to cause others to establish (or take preliminary steps to establish) a business with, any employee of Williams or an Affiliate, if such business is or will be a Competitive Business; or

(d) interfere with the relationship of Williams or an Affiliate with, or endeavor to entice away from Williams or an Affiliate, any Person who or which at any time during the period commencing one year prior to the Termination Date was or is, to Executive's knowledge, a material customer or material supplier of, or maintained a material business relationship with, Williams or an Affiliate.

6.4 Intellectual Property.

(a) During the period of Executive's employment with Williams or any Affiliate, and thereafter upon Williams' request, regardless of the reason for Executive's Separation from Service, Executive shall disclose immediately to Williams all Work Product that: (i) relates to the business of Williams or any Affiliate or any customer or supplier to Williams or an Affiliate or any of the products or services being developed, manufactured, sold or otherwise provided by Williams or an Affiliate or that may be used in relation therewith; or (ii) results from tasks or projects assigned to Executive by Williams or an Affiliate; or (iii) results from the use of the premises or personal property (whether tangible or intangible) owned, leased or contracted for by Williams or an Affiliate. Executive agrees that any Work Product shall be the property of Williams and, if subject to copyright, shall be considered a "work made for hire" within the meaning of the Copyright Act of 1976, as amended. If and to the extent that any such Work Product is not a "work made for hire" within the meaning of the Copyright Act of 1976, as amended, Executive hereby assigns, and agrees to assign, to Williams all right, title and interest in and to the Work Product and all copies thereof, and all copyrights , patent rights, trademark rights, trade secret rights and all other proprietary and intellectual property rights in the Work Product, without further consideration, free from any claim, lien for balance due, or rights of retention thereto on the part of Executive.

(b) Notwithstanding the foregoing, Williams agrees and acknowledges that the provisions of Section 6.4(a) relating to ownership and disclosure of Work Product do not apply to any inventions or other subject matter for which no equipment, supplies, facility, or trade secret information of Williams or an Affiliate was used and that are developed entirely on Executive's own time, unless: (i) the invention or other subject matter relates (a) to the business of Williams or an Affiliate, or (b) to the actual or demonstrably anticipated research or development of Williams or any Affiliate, or (ii) the invention or other subject matter results from any work performed by Executive for Williams or any Affiliate.

(c) Executive agrees that, upon disclosure of Work Product to Williams, Executive will, during his employment by Williams or an Affiliate and at any time thereafter, at the request and cost of Williams, execute all such documents and perform all such acts as Williams or an Affiliate (or their respective duly authorized agents) may reasonably require: (i) to apply for, obtain and vest in the name of Williams alone (unless Williams otherwise directs) letters patent, copyrights or other intellectual property protection in any country throughout the world, and when so obtained or vested to renew and restore the same; and (ii) to prosecute or defend any opposition proceedings in respect of such applications and any opposition proceedings or petitions or applications for revocation of such letters patent, copyright or other intellectual property protection, or otherwise in respect of the Work Product.

(d) In the event that Williams is unable, after reasonable effort, to secure Executive's execution of such documents as provided in Section 6.4(c), whether because of Executive's physical or mental incapacity or for any other reason whatsoever, Executive hereby irrevocably designates and appoints Williams and its duly authorized officers and agents as his agent and attorney-in-fact, to act for and on his behalf to execute and file any such application or applications and to do all other lawfully permitted acts to further the prosecution, issuance and protection of letters patent, copyright and other intellectual property protection with the same legal force and effect as if personally executed by Executive.

6.5 Non-Disparagement.

(a) Executive agrees not to make, or cause to be made, any statement, observation or opinion, or communicate any information (whether oral or written, directly or indirectly) that (i) accuses or implies that Williams and/or any of its Affiliates, together with their respective present or former officers, directors, partners, stockholders, employees and agents, and each of their predecessors, successors and assigns, engaged in any wrongful, unlawful or improper conduct, whether relating to Executive's employment (or the termination thereof), the business or operations of Williams, or otherwise; or (ii) disparages, impugns or in any way reflects adversely upon the business or reputation of Williams and/or any of its Affiliates, together with their respective present or former officers, directors, partners, stockholders, employees and agents, and each of their predecessors, successors and assigns.

(b) Williams agrees not to authorize any statement, observation or opinion, or communicate any information (whether oral or written, direct or indirect) that (i) accuses or implies that Executive engaged in any wrongful, unlawful or improper conduct relating to Executive's employment or termination thereof with Williams, or otherwise; or (ii) disparages, impugns or in any way reflects adversely upon the reputation of Executive.

(c) Notwithstanding anything contained herein to the contrary, nothing herein shall be deemed to preclude Executive or Williams from providing truthful testimony or information pursuant to subpoena, court order or other similar legal or regulatory process, provided, that to the extent permitted by law, Executive will promptly inform Williams of any such obligation prior to participating in any such proceedings.

6.6 Reasonableness of Restrictive Covenants.

(a) Executive acknowledges that the covenants contained in this Agreement are reasonable in the scope of the activities restricted, the geographic area covered by the restrictions, and the duration of the restrictions, and that such covenants are reasonably necessary to protect Williams' legitimate interests in its Confidential Information, its proprietary work, and in its relationships with its employees, customers, suppliers and agents.

(b) Williams has, and Executive has had an opportunity to, consult with their respective legal counsel and to be advised concerning the reasonableness and propriety of such covenants. Executive acknowledges that his observance of the covenants contained herein will not deprive Executive of the ability to earn a livelihood or to support his or her dependents.

(c) Executive understands he is bound by the terms of this Article VI, whether or not he receives severance payments under the Agreement or otherwise.

6.7 Right to Injunction: Survival of Undertakings.

(a) In recognition of the confidential nature of the Confidential Information, and in recognition of the necessity of the limited restrictions imposed by this Agreement, Executive and Williams agree that it would be impossible to measure solely in money the damages which Williams would suffer if Executive were to breach any of his obligations hereunder. Executive acknowledges that any breach of any provision of this Agreement would irreparably injure Williams. Accordingly, Executive agrees that if he breaches any of the provisions of this Agreement, Williams shall be entitled, in addition to any other remedies to which Williams may be entitled under this Agreement or otherwise, to an injunction to be issued by a court of competent jurisdiction, to restrain any breach, or threatened breach, of any provision of this Agreement without the necessity of posting a bond or other security therefor, and Executive hereby waives any right to assert any claim or defense that Williams has an adequate remedy at law for any such breach.

(b) If a court determines that any covenant included in this Article VI is unenforceable in whole or in part because of such covenant's duration or geographical or other scope, such court shall have the power to modify the duration or scope of such provision, as the case may be, so as to cause such covenant as so modified to be enforceable.

(c) All of the provisions of this Agreement shall survive any Separation from Service of Executive, without regard to the reasons for such termination. Notwithstanding Section 2.6, in addition to any other rights it may have, neither Williams nor any Affiliate shall have any obligation to pay or provide severance or other benefits (except as may be required under the Employee Retirement Income Security Act of 1974, as amended) after the Termination Date if Executive has materially breached any of Executive's obligations under this Agreement.

Article VII.

Non-Exclusivity of Rights

7.1 Waiver of Certain Other Rights. To the extent that Executive shall have received severance payments or other severance benefits under any other plan, program, policy, practice or procedure or agreement of any Williams Party prior to receiving severance payments or other severance benefits pursuant to Article II, the severance payments or other severance benefits under such other plan, program, policy, practice or procedure or agreement shall reduce (but not below zero) the corresponding severance payments or other benefits to which Executive shall be entitled under Article II. To the extent that Executive accepts payments made pursuant to Article II, he shall be deemed to have waived his right to receive a corresponding amount of future severance payments or other severance benefits under any other plan, program, policy, practice or procedure or agreement of any Williams Party.

7.2 Other Rights. Except as expressly provided in Section 7.1 and as provided in the Recitals to this Agreement, this Agreement shall not prevent or limit Executive's continuing or future participation in any benefit, bonus, incentive or other plan, program, policy, practice or procedure provided by a Williams Party and for which Executive may qualify, nor shall this Agreement limit or otherwise affect such rights as Executive may have under any other agreements with a Williams Party. Amounts that are vested benefits or that Executive is otherwise entitled to receive under any plan, program, policy, practice or procedure and any other payment or benefit required by law at or after the Termination Date shall be payable in accordance with such plan, program, policy, practice or procedure or applicable law except as expressly modified by this Agreement.

7.3 No Right to Continued Employment. Nothing in this Agreement shall guarantee the right of Executive to continue in employment, and Williams and the Employer retain the right to terminate Executive's employment at any time for any reason or for no reason.

Article VIII.

Claims Procedure

8.1 Filing a Claim.

(a) Each individual eligible for benefits under this Agreement ("Claimant") may submit his application for benefits ("Claim") to Williams (or to such other person as may be designated by Williams) in writing in such form as is provided or approved by Williams. A Claimant shall have no right to seek review of a denial or benefits, or to bring any action in any court to enforce a Claim, prior to his filing a Claim and exhausting his rights to review under Sections 8.1 and 8.2.

(b) When a Claim has been filed properly, it shall be evaluated and the Claimant shall be notified of the approval or the denial of the Claim within 30 days after the receipt of such Claim. A Claimant shall be given a written notice in which the Claimant shall be advised as to whether the Claim is granted or denied, in whole or in part. If a Claim is denied, in whole or in part, the notice shall contain (i) the specific reasons for the denial, (ii) references to pertinent provisions of this Agreement on which the denial is based, (iii) a description of any additional material or information necessary to perfect the Claim and an explanation of why such material or information is necessary, (iv) the Claimant's right to seek review of the denial and a description of the procedures for such review and (v) a statement regarding Claimant's right to bring a civil action under section 502(a) of ERISA following an adverse decision on appeal.

8.2 Review of Claim Denial. If a Claim is denied, in whole or in part, or if a Claim is neither approved nor denied within the 30-day period specified Section 8.1(b), the Claimant (or his or her authorized representative) shall have the right at any time to (a) request that Williams (or such other person as shall be designated in writing by Williams) review the denial or the failure to approve or deny the Claim, (b) review pertinent documents, and (c) submit issues and comments in writing. Within 30 days after such a request is received, Williams shall complete its review and give the Claimant written notice of its decision. Upon request and without charge, the Claimant will be provided reasonable access to and copies of all documents, records and other information relevant to the claim. Williams shall include in its notice to Claimant (i) the specific reasons for its decision, (ii) references to provisions of this Agreement on which its decision is based, (iii) a statement that the Claimant is entitled to receive, upon request and free of charge, reasonable access to and copies of all documents, records and other information relevant to the claim; and (iv) a statement regarding the Claimant's right to bring a civil action under ERISA Section 502(a) within 180 days of receipt of notice of denial on appeal.

Article IX.

Miscellaneous

9.1 No Assignability. This Agreement is personal to Executive and without the prior written consent of Williams shall not be assignable by Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by Executive's legal representatives.

9.2 Successors. This Agreement shall inure to the benefit of and be binding upon Williams and its successors and assigns. Williams will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business or assets of Williams (or the Employer during any Post-Change Period) to assume expressly and agree to perform this Agreement in the same manner and to the same extent that Williams (or, if applicable, the Employer) would be required to perform it if no such succession had taken place. Any successor to the business or assets of Williams (or any Employer) which assumes or agrees to perform this Agreement by operation of law, contract, or otherwise shall be jointly and severally liable with Williams (or the Employer) under this Agreement as if such successor were Williams (or the Employer). If Executive's employment is transferred from Williams to a Subsidiary, or from a Subsidiary to Williams or another Subsidiary, the rights and obligations of the Employer (determined prior to such transfer) shall automatically become the rights and obligations of the Employer (determined immediately following such transfer), without requiring the consent of Executive.

9.3 Payments to Beneficiary. If Executive dies before receiving amounts to which Executive is entitled under this Agreement, such amounts shall be paid in a lump sum to one or more beneficiaries designated in writing by Executive (each, a "Beneficiary"). If none is so designated, Executive's estate shall be his or her Beneficiary.

9.4 Non-Alienation of Benefits. Benefits payable under this Agreement shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, charge, garnishment, execution or levy of any kind, either voluntary or involuntary, before actually being received by Executive, and any such attempt to dispose of any right to benefits payable under this Agreement shall be void.

9.5 Severability. If any one or more Articles, Sections or other portions of this Agreement are declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not serve to invalidate any Article, Section or other portion not so declared to be unlawful or invalid. Any Article, Section or other portion so declared to be unlawful or invalid shall be construed so as to effectuate the terms of such Article, Section or other portion to the fullest extent possible while remaining lawful and valid.

9.6 Amendments. This Agreement shall not be amended or modified except by written instrument executed by Williams and Executive; provided however that notwithstanding the terms of this Agreement to the contrary, the terms of this Agreement shall be administered in such a way to comply with Code Section 409A as reasonably deemed appropriate by Williams; provided further however that notwithstanding anything to the contrary herein, Williams shall have the unilateral right to modify or amend this Agreement as it reasonably deems appropriate related to compliance with Code Section 409A. The parties to this Agreement intend that this Agreement meet the requirements of Internal Revenue Code Section 409A and recognize that it may be necessary to modify this Agreement to reflect guidance under Code Section 409A issued by the Internal Revenue Service.

9.7 Notices. All notices and other communications under this Agreement shall be in writing and delivered by hand, by nationally-recognized delivery service that promises overnight delivery, or by first-class registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to Executive, to Executive at his most recent home address on file with Williams.

If to Williams or the Employer:

The Williams Companies, Inc.
One Williams Center
Tulsa, Oklahoma 74172
Attention: General Counsel

or to such other address as either party shall have furnished to the other in writing. Notice and communications shall be effective when actually received by the addressee.

9.8 Joint and Several Liability. In the event that the Employer incurs any obligation to Executive pursuant to this Agreement, such Employer, Williams and each Subsidiary, if any, of which such Employer is a subsidiary shall be jointly and severally liable with such Employer for such obligation.

9.9 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together constitute one and the same instrument.

9.10 Governing Law. This Agreement shall be interpreted and construed in accordance with the laws of the State of Oklahoma, without regard to its choice of law principles, except to the extent preempted by federal law.

9.11 Captions. The captions of this Agreement are not a part of the provisions hereof and shall have no force or effect.

9.12 Rules of Construction. Reference to a specific law shall include such law, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing or superseding such section.

9.13 Number and Gender. Wherever appropriate, the singular shall include the plural, the plural shall include the singular, and the masculine shall include the feminine.

9.14 Tax Withholding. Williams may withhold from any amounts payable under this Agreement or otherwise payable to Executive any Taxes Williams determines to be required under applicable law or regulation and may report all such amounts payable to such authority as is required by any applicable law or regulation.

9.15 No Rights Prior to Change Date. Notwithstanding any provision of this Agreement to the contrary, this Agreement shall not entitle Executive to any compensation, severance or other payments or benefits of any kind prior to a Change Date.

9.16 Entire Agreement. This Agreement and the documents expressly referred to herein contain the entire understanding of Williams and Executive with respect to severance or benefits in relation to a Change in Control.

IN WITNESS WHEREOF, Executive and a duly authorized representative of The Williams Companies, Inc. have executed this Amended and Restated Change in Control Severance Agreement__________, 200___.

[INSERT EXECUTIVE NAME]

____

Date: ______________________________

THE WILLIAMS COMPANIES, INC., acting on behalf of itself and its Subsidiaries and Affiliates

By: ______________________________

Title: ______________________________

Date: ______________________________

EXHIBIT A

THE WILLIAMS COMPANIES, INC.
WAIVER AND RELEASE
CHANGE IN CONTROL SEVERANCE AGREEMENT (TIER ONE)

This agreement, release and waiver (the "Agreement"), made as of the ___ day of__________, 200 ___ (the "Effective Date"), is made by and among The Williams Companies, Inc. (together with all successors thereto, "Company") and **[INSERT EXECUTIVE NAME]** ("Executive").

WHEREAS, the Executive and the Company have entered into The Williams Companies, Inc. Change in Control Severance Agreement (Tier One) ("Severance Agreement");

NOW THEREFORE, in consideration for receiving benefits and severance under the Severance Agreement and in consideration of the representations, covenants and mutual promises set forth in this Agreement, the parties agree as follows:

1. Release. Except with respect to all of the Company's obligations under the Severance Agreement, the Executive, and Executive's heirs, executors, assigns, agents, legal representatives, and personal representatives, hereby releases, acquits and forever discharges the Company, its agents, subsidiaries, affiliates, and their respective officers, directors, agents, servants, employees, attorneys, shareholders, successors, assigns and affiliates, of and from any and all claims, liabilities, demands, causes of action, costs, expenses, attorneys fees, damages, indemnities and obligations of every kind and nature, in law, equity, or otherwise, known and unknown, suspected and unsuspected, disclosed and undisclosed, arising out of or in any way related to agreements, events, acts or conduct at any time prior to the day prior to execution of this Agreement that arose out of or were related to the Executive's employment with the Company or the Executive's termination of employment with the Company including, but not limited to, claims or demands related to wages. salary, bonuses, commissions, stock, stock options, or any other ownership interests in the Company, vacation pay, fringe benefits, expense reimbursements, sabbatical benefits, severance benefits, or any other form of compensation or equity or thing of value whatsoever; claims pursuant to under Title VII of the Civil Rights Act of 1964 as amended by the Civil Rights Act of 1991, 42 U.S.C. § 2000e, *et seq.*; 42 U.S.C. § 1981; 42 U.S.C. § 1983; 42 U.S.C. § 1985; 42 U.S.C. § 1986; the Equal Pay Act of 1963, 29 U.S.C. § 206(d); the National Labor Relations Act, as amended, 29 U.S.C. § 160, *et seq.*; the Americans With Disabilities Act of 1990, 42 U.S.C. § 12101,*et seq.*; the Employee Retirement Income Security Act of 1974, as amended, ("ERISA"), 29 U.S.C. § 1001, *et seq.*; the Age Discrimination in Employment Act of 1967, as amended by the Older Workers Benefit Protection Act of 1990, 29 U.S.C.§ 621,*et seq.*; the Family and Medical Leave Act of 1993, 29 U.S.C.§ 2601 *et seq.*; the Equal Pay Act; the Rehabilitation Act of 1973; the federal Worker Adjustment and Retraining Notification Act (as amended) and similar laws in other jurisdictions; the Oklahoma Anti-Discrimination Act, Okla. Stat., tit. 25, §§ 1101, *et seq.*, and any claims for wrongful discharge, breach of contract, breach of the implied covenant of good faith and fair dealing, fraud, discrimination, harassment, defamation, infliction of emotional distress, termination in violation of public policy, retaliation, including workers' compensation retaliation under state statutes, tort

law; contract law; wrongful discharge; discrimination; fraud; libel; slander; defamation; harassment; emotional distress; breach of the implied covenant of good faith and fair dealing; or claims for whistle-blowing, or other claims arising under any local, state or federal regulation, statute or common law. This Release does not apply to the payment of any and all benefits and/or monies earned, accrued, vested or otherwise owing, if any, to the Executive under the terms of a Company sponsored tax qualified retirement or savings plan and/or The Williams Companies Retirement Restoration Plan, except that the Executive hereby releases and waives any claims that his termination was to avoid payment of such benefits or payments, and that, as a result of his termination, he is entitled to additional benefits or payments. Additionally, this Release does not apply to the indemnification provided pursuant to the Severance Agreement. This Release does not apply to any claim or rights which might arise out of the actions of the Company after the date the Executive signs this Agreement.

2. No Inducement. Executive agrees that no promise or inducement to enter into this Agreement has been offered or made except as set forth in this Agreement, that the Executive is entering into this Agreement without any threat or coercion and without reliance or any statement or representation made on behalf of the Company or by any person employed by or representing the Company, except for the written provisions and promises contained in this Agreement.

3. Damages. The parties agree that damages incurred as a result of a breach of this Agreement will be difficult to measure. It is, therefore, further agreed that, in addition to any other remedies, equitable relief will be available in the case of a breach of this Agreement. It is also agreed that, in the event Executive files a claim against the Company with respect to a claim released by Executive herein (other than a proceeding before the EEOC), the Company may withhold, retain, or require reimbursement of all or any portion of the benefits and severance payments under the Severance Agreement until such claim is withdrawn by Executive.

4. Advice of Counsel; Time to Consider; Revocation. Executive acknowledges the following:

(a) Executive has read this Agreement, and understands its legal and binding effect. Executive is acting voluntarily and of Executive's own free will in executing this Agreement.

(b) Executive has been advised to seek and has had the opportunity to seek legal counsel in connection with this Agreement.

(c) Executive was given at least 21 days to consider the terms of this Agreement before signing it.

Executive understands that, if Executive signs this Agreement, Executive may revoke it within seven days after signing it by delivering written notification of intent to revoke within that seven day period. Executive understands that this Agreement will not be effective until after the seven-day period has expired.

5. Severability. If all or any part of this Agreement is declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not invalidate any other portion of this Agreement. Any section or a part of a section declared to be unlawful or invalid shall, if possible, be construed in a manner which will give effect to the terms of the section to the fullest extent possible while remaining lawful and valid.

6. Amendment. This Agreement shall not be altered, amended, or modified except by written instrument executed by the Company and the Executive. A waiver of any portion of this Agreement shall not be deemed a waiver of any other portion of this Agreement.

7. Counterparts. This Agreement may be executed in several counterparts, each of which shall be deemed to be an original, but all of which together will constitute one and the same instrument.

8. Headings. The headings of this Agreement are not part of the provisions hereof and shall not have any force or effect.

9. Rules of Construction. Reference to a specific law shall include such law, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing or superseding such section.

10. Applicable Law. The provisions of this Agreement shall be interpreted and construed in accordance with the laws of the State of Oklahoma without regard to its choice of law principles.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the dates specified below.

[INSERT EXECUTIVE NAME]

____

Date: _________________________

THE WILLIAMS COMPANIES, INC.

By: _________________________

Title: _________________________

Date: _________________________

ACKNOWLEDGMENT

I HEREBY ACKNOWLEDGE that The Williams Companies, Inc. ("the Company"), in accordance with the Age Discrimination in Employment Act of 1967, as amended by the Older Workers Benefit Protection Act of 1990, informed me in writing that:

(1) I should consult with an attorney before signing the Change in Control Severance Agreement ("Agreement") that was provided to me.

(2) I may review the Agreement for a period of up to twenty-one (21) days prior to signing the Agreement. If I choose to take less than twenty-one (21) days to review the Agreement, I do so knowingly, willingly and on advice of counsel.

(3) For a period of seven (7) days following the signing of the Agreement, I may revoke the Agreement, and that the Agreement will not become effective or enforceable until the seven (7) day revocation period has elapsed.

(4) Any Severance Benefits paid pursuant to the Agreement will be paid in accordance with the Company's normal pay cycle but will not be paid to me until the seven-day revocation period has elapsed.

(5) Company shall not accept my signed Agreement prior to the last day of my employment.

I HEREBY FURTHER ACKNOWLEDGE receipt of this Change in Control Severance Agreement on the __ day of __________, 200___.

WITNESS:

____

____
[INSERT EXECUTIVE'S NAME]

Exhibit 10.19

The Williams Companies, Inc.
Severance Pay Plan

Effective January 1, 2008

THE WILLIAMS COMPANIES, INC.
SEVERANCE PAY PLAN

(As Amended and Restated Effective as of January 1, 2008)

Article 1
Definitions

The following capitalized words and phrases when used in the text of the Plan shall have the meanings set forth below. Words in the masculine gender shall connote the feminine gender as well.

1.1 "Administrative Committee" means the committee appointed to administer this Plan which is comprised of those individuals who are serving on the Administrative Committee on December 31, 2004, as well as any individual who becomes a member of the Administrative Committee pursuant to Section 5.4, until the time that any such individual ceases to be a member of the Administrative Committee pursuant to Section 5.4 of the Plan. The duties of the Administrative Committee are described in Article 5 of the Plan.

1.2 "Affiliate" means any Person that directly or indirectly, through one (1) or more intermediaries, controls, is controlled by or is under common control with the Company.

1.3 "Aggregate Compensation" means Regular Wage Base and any annual cash incentive awards from a Participating Company or Affiliate annual incentive program.

1.4 "Base Salary" means the amount a Participant is entitled to receive as wages or salary on an annualized basis, including any salary deferral contributions made to any defined contribution plan maintained by the Participating Company and any amounts contributed by an Employee to any cafeteria plan, flexible benefits plan or qualified transportation plan maintained by the Participating Company in accordance with Sections 125, 132 and related provisions of the Code, but excluding all special pay, bonus, overtime, incentive compensation, commissions, cost of living pay, housing pay, relocation pay, other taxable fringe benefits and all extraordinary compensation, payable by the Company or any of its Affiliates as consideration for the Participant's services, as determined on the date immediately preceding termination of employment, except that in the case of a termination of employment for Good Reason, Base Salary shall be determined as of the date immediately preceding the event which constitutes Good Reason.

1.5 "Benefits Committee" means the committee comprised of those individuals who were serving on the Benefits Committee on December 31, 2004, as well as any individual who becomes a member of the Benefits Committee pursuant to Section 5.3, until the time that any such individual ceases to be a member of the Benefits Committee pursuant to Section 5.3 of the Plan. The purely settlor duties of the Benefits Committee are described in Articles 5 and 6 of the Plan.

1.6 "Board of Directors" means the board of directors of the Company.

1.7 "Cause" means the occurrence of any one (1) or more of the following, as determined in the good faith and reasonable judgment of the Administrative Committee:

(a) willful failure by an Employee to substantially perform his duties (as they existed immediately prior to a reduction in force, job elimination or Change in Control), other than any such failure resulting from a disability as defined in the Participating Company or Affiliate disability program; or

(b) Employee's conviction of or plea of *nolo contendere* to a crime involving fraud, dishonesty or any other act constituting a felony involving moral turpitude or causing material harm, financial or otherwise, to the Company or an Affiliate; or

(c) Employee's willful or reckless material misconduct in the performance of his duties which results in an adverse effect on the Company or an Affiliate; or

(d) Employee's willful or reckless violation or disregard of the code of business conduct or other published policy of the Company or an Affiliate; or

(e) Employee's habitual or gross neglect of duties.

1.8 "Change Date" means the date on which a Change in Control first occurs.

1.9 "Change in Control" means the occurrence of: (i) a Change in the Ownership of the Company, as defined below; (ii) a Change in Effective Control of the Company, as defined below; or (iii) a Change in the Ownership of a Substantial Portion of the Assets of the Company, as defined below. To qualify as a Change in Control event, the occurrence of the event shall be objectively determinable, strictly ministerial, and shall not involve any discretionary authority by the Plan Administrator. Code Section 318(a) shall be applied to determine stock ownership for purposes of this section. Substantially vested stock underlying a vested option is considered owned by the person who holds the vested option (and the stock underlying an unvested option is not considered owned by the person who holds an unvested option). To qualify as a Change in Control with respect to a Participant, the Change in Control must relate to: (x) the corporation for whom the Participant is performing services at the time of the Change in Control event; (y) the corporation that is liable for the payment of benefits under this Plan (or all corporations which are liable for payment if more than one corporation is liable) but only if either the benefits are attributable to the performance of service by the Participant for such corporation (or corporations) or there is a bona fide business purpose for such corporation (or corporations) to be liable for such payment and, in either case, no significant purpose of making such corporation or corporations liable for such payment is the avoidance of Federal income tax; or (z) a corporation that is a majority shareholder of a corporation identified in subsections (x) or (y) above, or any corporation in a chain of corporations in which each corporation is a majority shareholder of another corporation in the chain, ending in a corporation identified in subsections (x) or (y) above. The provisions of Treas. Reg. § 1.409A-3, as amended, shall govern with respect to the definition of terms as used therein and in the interpretation of whether a Change in Control has occurred.

(a) A "Change in the Ownership of the Company" occurs on the date that any one person or more than one person Acting as a Group, as defined below, acquires ownership of stock of the Company ("Stock") that, together with Stock held by such person or group, constitutes more than fifty percent (50%) of the total fair market value or total voting power of the Stock. However, if any one person or more than one person Acting as a Group, is considered to own more than fifty percent (50%) of the total fair market value or total voting power of the Stock, the acquisition of additional Stock by the same person or persons is not considered to cause a Change in the Ownership of the Company. An increase in the percentage of Stock owned by any one person, or persons Acting as a Group, as a result of a transaction in which the Company acquires its Stock in exchange for property will be treated as an acquisition of Stock for purposes of this subsection. This subsection applies only when there is a transfer of Stock (or issuance of Stock) and Stock remains outstanding after the transaction.

(b) "Acting as a Group" persons will not be considered to be Acting as a Group solely because they purchase or own Stock at the same time or as a result of the same public offering. However, persons will be considered to be Acting as a Group if they are owners of a corporation that enters into a merger, consolidation, purchase or acquisition of Stock, or similar business transaction with the Company. If a person owns stock in both corporations that enter into a merger, consolidation, purchase or acquisition of Stock or similar transaction involving another corporation, such shareholder is considered to be Acting as a Group with other shareholders only in such corporation prior to the transaction giving rise to the change and not with respect to the ownership interest in the other corporation.

(c) A "Change in the Effective Control of the Company" occurs only on either of the following dates: (i) The date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) ownership of the Stock possessing thirty percent (30%) or more of the total voting power of the Stock of the Company; or (ii) The date a majority of members of the Board of Directors is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board of Directors before the date of the appointment or election.

If any one person, or more than one person Acting as a Group, is considered to be in effective control of a Company, the acquisition of additional control of the Company by the same person or persons is not considered to cause a Change in the Effective Control of the Company.

(d) A "Change in the Ownership of a Substantial Portion of the Assets of the Company" occurs on the date that any one person, or more than one person Acting as a Group, acquires (or has acquired during the twelve (12)-month period ending on the date of the most recent acquisition by such person or persons) assets from the Company that have a total gross fair market value equal to or more than forty percent (40%) of the total gross fair market value of all assets of the Company immediately prior to such acquisition or acquisitions. For this purpose, the gross fair market value means the value of the assets of the Company or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. Notwithstanding the foregoing, there is no Change in the Ownership of a Substantial Portion of the Assets of the Company when there is a transfer of assets to an entity that is controlled by the shareholders of the Company immediately after the transfer. A transfer of assets by the Company is not treated as a Change in the Ownership of a Substantial Portion of the Assets of the Company if the assets are transferred to: (i) a shareholder of the Company (immediately before the asset transfer) in exchange for or with respect to its Stock; (ii) an entity, fifty percent (50%) or more of the total value or voting power of which is owned, directly or indirectly, by the Company; (iii) a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock; or (iv) an entity, at least fifty percent (50%) of the total value or voting power of which is owned, directly or indirectly, by a person, or more than one person Acting as a Group, that owns, directly or indirectly, fifty percent (50%) or more of the total value or voting power of all the outstanding Stock. For purposes of this subsection (d), and except as otherwise provided, a person's status is determined immediately after the transfer of assets.

1.10 "Code" means the Internal Revenue Code of 1986, as amended from time to time. References to a particular section of the Code include references to regulations and rulings thereunder and to successor provisions.

1.11 "Company" means The Williams Companies, Inc., a Delaware corporation and any successor or successors thereto that continue this Plan pursuant to Section 6.1 or otherwise.

1.12 "Compensation Committee" means the Committee of the Board of Directors designated as the Compensation Committee.

1.13 "Comparable Offer of Employment" means an offer of employment for a position with the Company, any of its Affiliates, or any successor of the Company or its Affiliates that provides for a Regular Wage Base equal to or greater than the Participant's Regular Wage Base immediately preceding the Participant's termination date. A successor of the Company or any of its Affiliates shall include, but shall not be limited to, any entity (or its Affiliate) involved in or in any way connected with a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or any other transaction. A Comparable Offer of Employment includes, without limitation, a position that requires the Employee to transfer to a different work location (without your consent), but only so long as the Employee's commuting distance to the new work location is not increased more than fifty (50) miles beyond the commuting distance to his or her current work location (except for travel reasonably required in the performance of your duties).

1.14 "Effective Date" means January 1, 2008, which is the effective date of this amendment and restatement.

1.15 "Employee" means any regular full-time or part-time employee in the service and on the payroll of a Participating Company as a common law employee with the exception of any employee who is excluded either by this Section 1.15 or Section 2.2. An Employee is considered as part-time if he is regularly scheduled to work at least fifty percent of the number of hours in the normal workweek established by a Participating Company. A regular employee receiving benefits under a Participating Company's Short-Term Disability Program or Long-Term Disability Program is an Employee for purposes of this Plan. Employee shall not include:

(a) an Employee who is a member of a group of Employees represented by a collective bargaining representative, unless such agreement expressly provides for coverage of bargaining unit employees under the Plan;

(b) an Employee who is not a resident of the United States and not a citizen of the United States;

(c) a nonresident alien;

(d) a weekly-paid employee employed at a retail petroleum convenience store in any capacity other than a store manager;

(e) a seasonal employee, temporary employee, leased employee, term employee, or an employee not employed on a regularly scheduled basis;

(f) a person who has a written employment contract or other contract for services, unless such contract expressly provides that such person is an employee;

(g) a person who is paid through the payroll of a temporary agency or similar organization regardless of any subsequent reclassification as a common law employee;

(h) a person who is designated, compensated or otherwise treated as an independent contractor by a Participating Company or its Affiliates regardless of any subsequent reclassification as a common law employee;

(i) a person who has a written contract with a Participating Company or its Affiliates which states either that such person is not an employee or that such person is not entitled to receive employee benefits from a Participating Company for services under such contract;

(j) an individual who is not contemporaneously classified as an Employee for purposes of the Participating Company's payroll system. In the event any such individual is reclassified as an Employee for any purpose, including, without limitation, as a common law or statutory employee, by any action of any third party, including, without limitation, any government agency, or as a result of any private lawsuit, action or administrative proceeding, such individual will, notwithstanding such reclassification, remain ineligible for participation hereunder and will not be considered an eligible Employee. In addition to and not in derogation of the foregoing, the exclusive means for an individual who is not contemporaneously classified as an Employee of the Participating Company's payroll system to become eligible to participate in this Plan is through an amendment to this Plan which specifically renders such individual eligible for participation hereunder;

(k) any individual retained by a Participating Company or its Affiliates directly or through an agency or other party to perform services for an Employer (for either a definite or indefinite duration) in the capacity of a fee-for-service worker or independent contractor or any similar capacity including, without limitation, any such individual employed by temporary help firms, technical help firms, staffing firms, employee leasing firms, professional employer organizations or other staffing firms, whether or not deemed to be a "common law" employee; or

(l) any Employee of the Company or its Affiliates that holds a position that has been classified as an executive position by the Company's executive compensation department.

1.16 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time. References to a particular section of ERISA include references to regulations and rulings thereunder and to successor provisions.

1.17 "Good Reason" means the occurrence, within a pre-determined limited period of time not to exceed two (2) years following the initial existence of one (1) or more of the following conditions arising without the consent of the Participant:

(a) a material diminution in the Participant's "base compensation" as such term is defined pursuant to guidance under Section 409A of the Code issued by the Internal Revenue Service; or

(b) a material diminution in the Participant's authority, duties, or responsibilities; or

(c) a material diminution in the authority, duties, or responsibilities of the supervisor to whom the Participant is required to report, including a requirement that a Participant report to a corporate officer or employee instead of reporting directly to the Board of Directors of the Company or any of its Affiliates (or similar governing body with respect to an entity other than a corporation); or

(d) a material diminution in the budget over which the Participant retains authority; or

(e) a material change in the geographic location at which the Participant must perform the services; or

(f) any other action or inaction that constitutes a material breach by the Company or the Affiliate that employs the Participant of the agreement under which the Participant provides services.

The amount, time, and form of payment upon the “separation from service” (as such term is defined in Treasury Regulations issued under Code Section 409A) must be substantially identical to the amount, time and form of payment payable due to an actual involuntary separation from service, to the extent such a right exists. The Participant must be required to provide notice to the Company or any of its Affiliates of the existence of the condition described in this Section 1.17 of this Plan within a period not to exceed ninety (90) days of the initial existence of the condition, upon the notice of which the service recipient must be provided a period of at least thirty (30) days during which it may remedy the condition and not be required to pay the amount.

[Further, no act or omission shall be ‘Good Reason’ if Participant has consented in writing to such act or omission.

1.18 “Leave of Absence” means an absence, with or without compensation, authorized on a non-discriminatory basis by the Company or any of its Affiliates. For the purposes of this Plan, Leave of Absence includes any leave of absence other than a Family and Medical Leave of Absence or Military Leave of Absence.

1.19 “Participant” means an Employee participating in the Plan as provided in Article 2.

1.20 “Participating Company” means the Company and any Affiliate of the Company, which has adopted this Plan in accordance with Section 6.11.

1.21 “Person” means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporate entity or government instrumentality, division, agency, body or department.

1.22 “Plan” means The Williams Companies, Inc. Severance Pay Plan.

1.23 “Plan Administrator” means the Administrative Committee appointed under Article 5.

1.24 “Plan Year” means the twelve (12) month period from January 1 through December 31.

1.25 “Regular Wage Base” means an Employee’s total weekly salary or wages, including any salary deferral contributions made to any defined contribution plan maintained by the Participating Company and any amounts contributed by an Employee to any cafeteria plan, flexible benefit plan or qualified transportation plan maintained by the Participating Company in accordance with Sections 125, 132 and related provisions of the Code, but excluding any bonuses, overtime, incentive compensation, commissions, cost of living pay, housing pay, relocation pay, other taxable fringe benefits and all other extraordinary compensation.

1.26 "Related Party" means an Affiliate or any employee benefit plan (or any related trust) sponsored or maintained by the Company or any of its Affiliates.

1.27 "Sponsor" means The Williams Companies, Inc., a Delaware corporation.

1.28 "Years of Service" means a Participant's length of service with the Participating Company as set by the latest hire date or rehire date of such Participant. For purposes of this Plan, after the first year of service as a Participant, only full, completed years of service will be counted. Service with a predecessor company will not be included unless, and to the extent that, the Plan Administrator determines such service be included and notifies the Participant in writing that such service is included. Notwithstanding anything to the contrary above, effective as of January 1, 2008, with respect to a participant who was outsourced to International Business Machines Corporation ("IBM") at some point on or after July 1, 2004, that was subsequently in-sourced back to the Company or any of its Participating Companies with no break in service between his or her outsourced employment with IBM and his or her in-sourcing back to the Company or any Participating Companies, then such Participant's latest hire date prior to the outsourcing to IBM shall be used to determine the number of Years of Service and in addition, the time spent at IBM during the outsourcing prior to the direct in-sourcing shall also be included in the determination of the number of Years of Service for such Participant.

If a Participant is terminated for any reason other than Cause and is rehired by the Participating Company within twelve (12) months of such termination date, years of service prior to such termination will be bridged and used in determining years of service for the purposes of severance pay benefits in the event the Participant becomes eligible for severance pay. The Plan Administrator's determination of Years of Service in its sole and absolute discretion will be final and binding on all persons to the maximum extent permitted by law.

Article 2
Eligibility

2.1 Eligibility. Any Employee, who is not excluded pursuant to Section 2.2, shall be entitled to become a Participant in the Plan only when and only if all of the following conditions of subsection (a), (b) or (c) are met:

(a) The senior officer of the Company responsible for compensation or benefits, or such senior officer's designee, approves a reduction in force or job elimination and the Employee is notified in writing that employment is being involuntarily terminated due to the elimination of his position. The Employee will become a Participant on his designated termination date, provided the Employee remains in employment until his designated termination date.

(b) The Employee's employment is terminated involuntarily or for Good Reason within two (2) years after a Change in Control, in which case, the Employee will become a Participant upon the date of employment termination.

(c) The Employee is involuntarily terminated from employment by the Company within the thirty (30) day period prior to a Change in Control for the purpose of avoiding application of this Plan, in which case, the Employee will become a Participant upon the date of involuntary termination.

2.2 Exclusions. Notwithstanding the provisions of Section 2.1, an Employee will not become a Participant in the Plan if any of the following conditions occur:

(a) An Employee discharged for Cause.

(b) An Employee voluntarily resigns for any reason, including retirement, except in the case of resignation for Good Reason within two (2) years after a Change in Control.

(c) An Employee accepts any benefits under an early retirement incentive plan.

(d) An Employee fails to make a bona fide effort to secure employment within a Participating Company or any of its Affiliates, or any successor of the Company or its Affiliates.

(e) An Employee transfers to or receives a Comparable Offer of Employment from a Participating Company or any of its Affiliates.

(f) An Employee receives a Comparable Offer of Employment after a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or other transaction.

(g) An Employee accepts an offer of employment with a Participating Company or any of its Affiliates, whether or not such offer of employment constitutes a Comparable Offer of Employment.

(h) An Employee accepts an offer of employment with any purchaser company or resultant entity, or an affiliate of such a company or entity, after a corporate rearrangement, total or partial merger, acquisition, sale of stock, sale of assets or other transaction, whether or not such offer of employment constitutes a Comparable Offer of Employment.

(i) An Employee dies prior to his termination of employment.

(j) Except as provided in subsection (k), an Employee on a Leave of Absence at the time he is notified that his employment is being terminated due to a reduction in force.

(k) An Employee receiving benefits under the Short-Term Disability Program. This exclusion may not apply if the Employee would have returned to work within the initial six-month period of short-term disability had his termination of employment not occurred and a senior officer of the Company responsible for compensation or benefits, or such senior officer's designee, approves eligibility for severance upon release to return to work in his sole discretion. This exclusion does not apply in the event of a Change in Control.

(l) An Employee receiving benefits under the Long-Term Disability Program.

(m) An Employee has a written employment contract which contains severance provisions.

(n) An Employee received or is eligible to receive more favorable severance pay benefits under any other severance pay plan, agreement or arrangement of a Participating Company, any of its Affiliates, or any successor of a Participating Company.

Article 3
Benefits

3.1 Severance Pay. Except as provided in Section 3.7, subject to the Participant signing a release of claims prepared by the Company within fifty (50) days of termination date, a Participant will be eligible for severance pay benefits under this Section 3.1 equal to:

(a) the product of: (i) two (2) weeks multiplied by; (ii) the Participant's Regular Wage Base, if the Participant has less than one (1) full, completed Year of Service; or

(b) the product of: (i) two (2) weeks for each full, completed Year of Service, with a minimum of six (6) weeks and a maximum of fifty-two (52) weeks, multiplied by; (ii) the Participant's Regular Wage Base, if the Participant has completed at least one (1) full Year of Service.

3.2 Change in Control Severance Pay. Subject to the Participant signing a release of claims prepared by the Company within fifty (50) days of termination of employment, if a Participant's employment is terminated for Good Reason or involuntarily within two (2) years after a Change in Control, the Participant will be eligible for severance pay benefits under this Section 3.2 in lieu of any benefits under Section 3.1 with the amount of such benefits equal to the sum of:

(a) the product of: (i) the number of the Participant's full, completed Years of Service multiplied by; (ii) three (3), and multiplied by; (iii) the Participant's Regular Wage Base;

(b) the product of: (i) Participant's Regular Wage Base multiplied by; (ii) the quotient of the Participant's Base Salary divided by ten thousand (10,000); and

(c) the product of: (i) the Participant's target annual bonus (with respect to the calendar year in which the termination occurs) multiplied by; (ii) a fraction, the numerator of which equals the number of days from and including the first day of such calendar year through and including the date of termination, and the denominator of which equals three hundred and sixty-five (365) (reduced by any annual bonus amount received with respect to such calendar year).

Notwithstanding the foregoing, the sum of subsections (a) and (b) of this Section 3.2 shall not be less than the product of the Participant's Regular Wage Base multiplied by twelve (12) nor more than the product of the Participant's Regular Wage Base multiplied by one hundred and four (104).

3.3 Notice. Any Participant who is terminated and receives less than two (2) weeks notice from a Participating Company will receive, in addition to the benefits provided in Section 3.1 or 3.2 (whichever applies), severance pay for the lack of notice. Weeks or fractions thereof, will be granted which is equal to the difference between two (2) weeks and the number of days notice received by the Participant. The amount of severance pay will be equal to the number of weeks and/or fractions thereof granted to a Participant under this Section 3.3 times the Participant's Regular Wage Base. No payment will be made under this Section 3.3 if total severance pay exceeds the maximum benefit allowed.

3.4 Form of Payment. Severance benefits payable to a Participant under Section 3.1 shall be paid in a lump sum no later than sixty (60) days from the date of the Participant's termination of employment.

3.5 Other Benefit Plans. Participants, regardless of whether they sign the release of claims required to receive severance payments, who are otherwise entitled to receive severance pay and who are eligible to continue participation in certain welfare benefit plans may choose to continue their participation in accordance with this Section 3.5. Continued participation in such welfare benefit plans is subject to the terms and conditions of the applicable plan documents or insurance contracts in effect on the date of the Participant's termination from employment. Generally, the Participant has the option to elect the currently maintained Participating Company group medical and dental plan that he is currently enrolled for up to 18 months under the Consolidated Omnibus Budget Reconciliation Act ("COBRA") continuation coverage. If the Participant timely and properly elects COBRA coverage, the premiums for COBRA coverage will be limited to the active employee rate for the initial three months of coverage. At the end of this three-month period, the Participant will be required to pay the full cost for medical and/or dental benefits under COBRA for the remainder of the 18-month period. Participation in the Participating Company group medical and dental plan will generally cease on the date the Participant or his dependents become covered under any other medical plan or dental plan.

3.6 Paid-Time Off ("PTO") Program. A Participant, regardless of whether he signs the release of claims required to receive severance payments, shall be paid a single lump sum payment for applicable PTO hours earned but not taken prior to the Participant's employment termination. PTO time will not be considered for purposes of continued coverage under any of the other various employee benefit plans maintained by the Participating Company.

3.7 Rehired Participants after Receipt of Severance Pay. This Section 3.7 applies to Participants rehired by a Participating Company or any Affiliate after receipt of severance pay under Section 3.1.

(a) Severance Pay. The Participant will be entitled to keep a portion of his severance pay equal to the number of weeks and/or fraction of weeks between his termination date and the date of rehire. Any remainder must be returned to the Participating Company that paid the severance pay upon rehire or it will be deducted from his wages paid after rehire.

If a Participant is rehired within twelve (12) months of his termination date and again becomes eligible for severance pay due to a subsequent event within twelve (12) months of rehire, subject to the Participant signing a release of claims prepared by the Company within fifty (50) days of such subsequent termination date, the Participant will be eligible to receive the greater of:

(i) the sum of any remaining severance not yet received from the initial termination date in accordance with Section 3.1, plus two (2) weeks of severance pay; or

(ii) two (2) weeks of severance pay.

Severance pay under this Section 3.7 will be paid in accordance with Section 3.4.

(b) PTO. If a Participant is rehired within the same calendar year in which his employment was terminated and he received payment for PTO earned but not taken, he may either retain the payment and forfeit PTO time for which he was eligible prior to his employment termination, or he may return to the Company the amount he received and reinstate PTO time for which he was eligible prior to termination.

3.8 Discretionary Benefits. Under no circumstances will any discretionary benefits be paid unless the senior officer of the Company responsible for compensation or benefits, or such senior officer’s designee, signs a written document describing such benefits. Payment of such discretionary benefits will be made only in accordance with the terms of that document.

3.9 No Vesting. Employees have no vested right to any benefits set forth in the Plan until such time as an Employee becomes entitled to receive benefits under Article 2; however, the Participant must timely execute a release in accordance with Section 3.1 or 3.2 (whichever applies) to receive any benefits under this Plan.

3.10 Integration with Plant Closing Law(s). To the extent that a federal, state or local law, including, but not limited to the Worker Adjustment and Retraining Act, requires a Participating Company, as an employer, to provide notice and/or make a payment to an

Employee because of that Employee’s involuntary termination, or pursuant to a plant closing law, the benefit payable under this Plan, including without limitation benefits payable under Section 3.3, shall be reduced by any Regular Wage Base paid during such notice period and/or by such other required payment.

Nothing in this section or any other section of this Plan shall be used to reduce benefits under this Plan because of payments under state unemployment insurance laws.

Article 4
Claims

4.1 Claims for Benefits. To obtain payment of any benefits under the Plan, a Participant must comply with such rules and procedures as the Plan Administrator may prescribe.

4.2 Claims Procedure. The Plan Administrator shall adopt, and may change from time to time, claims procedures, provided that such claims procedures and changes thereof shall conform to Section 503 of the Employee Retirement Income Security Act of 1974 and the regulations promulgated thereunder. Such claims procedures, as in effect from time to time, shall be deemed to be incorporated herein and made a part hereof.

Article 5
Administration

5.1 Fiduciaries. Under certain circumstances, the Administrative Committee may be determined by a court of law to be a fiduciary with respect to a particular action under the Plan; provided that any claims administrator will be a named fiduciary with respect to claims and appeals related to benefit determinations.

5.2 Allocation of Responsibilities.

(a) Administrative Committee. The Administrative Committee shall serve as Plan Administrator and shall have exclusive authority and responsibility for those functions set forth in Section 5.4 and in other provisions of this Plan.

(b) Claims Administrator. Claims Administrator shall have the responsibility to make claims and appeals decisions related to benefit determinations in accordance with the claims procedure.

5.3 Provisions Concerning the Benefits Committee.

(a) Membership and Voting. The Benefits Committee shall consist of not less than three (3) members and not more than five (5) members and vacancies of the Benefits Committee shall be filled by the remaining members of the Benefits Committee.

(b) Powers and Duties of Benefits Committee. The Benefits Committee shall have the authority and responsibility for:

(i) Those responsibilities as detailed in Article 6.

The Benefits Committee may appoint such accountants, counsel, specialists, and other persons as it deems necessary or desirable in connection with its duties under this Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an affiliate.

5.4 Provisions Concerning the Administrative Committee.

(a) Membership and Voting. The Administrative Committee shall consist of not less than three (3) members. The Administrative Committee may remove any of its members at any time, with or without cause, by written notice to such member. Any member may resign by delivering a written resignation to the Administrative Committee. Vacancies in the Administrative Committee arising by death, resignation or removal shall be filled by the Administrative Committee. The Administrative Committee shall act by a majority of its members at the time in office, and such action may be taken by a vote at a meeting, in writing without a meeting, or by telephonic communications. Attendance at a meeting shall constitute waiver of notice thereof. A member of the Administrative Committee who is a Participant in the Plan shall not vote on any question relating specifically to such Participant. Any such action shall be voted or decided by a majority of the remaining members of the Administrative Committee. The Administrative Committee shall designate one of its members as the Chairman and shall appoint a Secretary who may, but need not, be a member. The Administrative Committee may appoint from its members such subcommittees with such powers as the Administrative Committee shall determine.

(b) Duties of Administrative Committee. Except as otherwise expressly provided in the Plan, the Administrative Committee shall be responsible for the administration of the Plan, with all powers and discretionary authority necessary to enable the Administrative Committee to carry out its duties in that respect. Not in limitation, but in amplification of the foregoing, the Administrative Committee shall have the following duties, responsibilities and full discretionary authority with respect to the administration of the Plan:

(i) To prescribe procedures and forms to be followed by Participants in filing applications for benefits and for furnishing evidence necessary to establish their rights to benefits under the Plan;

(ii) To interpret the Plan, and to resolve ambiguities, inconsistencies and omissions in accordance with the intent of the Plan;

(iii) To decide on questions concerning the Plan and the eligibility of an Employee to participate in the Plan, in accordance with the provisions of the Plan;

(iv) To make benefit payments directly to Participants and/or their assignees entitled to benefits under the Plan;

(v) To find facts and to grant or deny claims relating to eligibility or the payment or nonpayment of benefits under the Claims Procedure in accordance with Article 4;

(vi) To obtain from the Participating Companies, Participants and others, such information as it shall deem to be necessary for the proper administration of the Plan;

(vii) To take all steps to properly administer the Plan in accordance with its terms and the requirements of applicable law;

(viii) To execute any certificate, instrument or other written direction on behalf of the Plan with respect to the administration of this Plan; and

(ix) To appoint such accountants, counsel, specialists, and other persons as it deems necessary or appropriate in connection with the administration of this Plan. In this regard, the Administrative Committee may cause the Company to enter into contracts with third parties if the Administrative Committee determines such contracts are desirable in connection with the administration of the Plan. Such accountants and counsel may, but need not, be accountants and counsel for the Company or an Affiliate.

The Administrative Committee shall have no power to add to any benefit not provided under the provisions of the Plan, nor to waive or fail to apply any requirement of eligibility for a benefit under the Plan.

No determination of the Administrative Committee for any Participant shall create a basis for retroactive adjustment for any other Participant.

All regulations, procedures, and rules with respect to any of the above-described duties, responsibilities, and authorities shall be promulgated by the Administrative Committee (or its delegate) in its sole discretion, and all such regulations, procedures, and rules shall be conclusive and binding on all persons to the maximum extent permitted by law.

All decisions of the Administrative Committee with respect to the Plan's administration, including, but not limited to, interpretations of the Plan, benefit determinations, claims decisions relating to eligibility, and questions concerning the administration and application of the Plan, shall be made by the Administrative Committee (or its delegate) in its sole discretion, and all such determinations and decisions shall be conclusive and binding on all persons to the maximum extent permitted by law.

(c) Recordkeeping. The Administrative Committee or its delegate shall keep full and complete records of the administration of the Plan. The Administrative Committee or its delegate shall prepare such reports and such information concerning the Plan and the administration thereof by the Administrative Committee (or its delegate) as may be required under the Code or ERISA and the regulations promulgated thereunder.

(d) Inspection of Records. The Administrative Committee or its delegate shall, during normal business hours, make available to each Participant for examination by him at the principal office of the Administrative Committee, a copy of the Plan and such records of the Administrative Committee as may pertain to such Participant. No Participant shall have the right to inquire as to or inspect the accounts or records with respect to other Participants.

5.5 Delegation of Responsibilities; Bonding.

(a) Delegation and Allocation. The Administrative Committee shall have the authority to delegate or allocate, from time to time, by a written instrument, all or any part of its responsibilities under this Plan to such person or persons as it may deem advisable and in the same manner to revoke any such delegation or allocation of responsibility. Any action of a person in the exercise of such delegated or allocated responsibility shall have the same force and effect for all purposes hereunder as if such action had been taken by the Administrative Committee. The Administrative Committee shall not be liable for any acts or omissions of any such person, who shall periodically report to the Administrative Committee concerning the discharge of the delegated or allocated responsibilities.

(b) Bonding. The members of the Benefits Committee, and the Administrative Committee shall serve without bond (except as expressly required by federal law) and without compensation for their services as such.

5.6 No Joint Fiduciary Responsibilities. This Plan is intended to allocate to the Administrative Committee the individual responsibility for the prudent execution of the functions assigned to it, and none of such responsibilities or any other responsibility shall be shared by any other entity unless such sharing is provided for by a specific provision of the Plan. Whenever one fiduciary is required herein to follow the directions of another fiduciary, the two fiduciaries shall not be deemed to have been assigned a shared responsibility, but the responsibility of a fiduciary receiving such directions shall be to follow them insofar as such instructions are on their face proper under applicable law.

5.7 Fiduciary Capacity. Any person or group of persons may serve in more than one fiduciary capacity with respect to the Plan.

5.8 Right to Receive and Release Necessary Information. The Administrative Committee may release or obtain any information necessary for the application, implementation and determination of this Plan or other Plans without consent or notice to any person. This information may be released to or obtained from any insurance company, organization or person. Any individual claiming benefits under this Plan shall release to the Administrative Committee such information as the Administrative Committee, in its sole and absolute discretion, determines to be necessary to implement this provision.

Article 6
General Provisions

6.1 Successor to Company. This Plan shall bind any successor (whether direct or indirect, by purchase, merger, consolidation, reorganization or otherwise) which becomes such after Change in Control has occurred to all or substantially all of the business and/or assets of the Company in the same manner and to the same extent that the Company would be obligated under this Plan if no succession had taken place. In the case of any transaction in which a successor (which becomes such after a Change in Control of the Company has occurred) would not by the foregoing provision or by operation of law be bound by this Plan, the Company shall require such successor expressly and unconditionally to assume and agree to perform the Company's obligations under this Plan, in the same manner and to the same extent that the Company would be required to perform if no such succession had taken place. The term "Company," as used in this Plan, shall mean the Company and any successor or assignee to the business or assets that by reason hereof becomes bound by this Plan.

6.2 Duration. The Plan shall continue indefinitely unless terminated as provided in subsection 6.3 hereof.

6.3 Amendment and Termination.

(a) Subject to subsection 6.3(b), the Compensation Committee and/or the Benefits Committee, in its settlor capacity, reserves the right at any time to terminate the Plan. The Compensation Committee reserves the right at any time and from time to time, and retroactively if deemed necessary or appropriate, to modify or amend in whole or in part any or all of the provisions of the Plan. The Benefits Committee shall have the right at any time and from time to time, and retroactively if deemed necessary or appropriate, to modify or amend in whole or in part any or all of the provisions of the Plan, provided such modification or amendment constitutes a non-material amendment. Non-material amendments consist of: (i) changes required by applicable law; (ii) changes (including retroactive changes) necessary to maintain the Plan's qualification status; (iii) modifications of the administrative provisions of the Plan to cause the Plan to operate more efficiently; (iv) changes required as part of the collective bargaining process; and (v) modifications or amendments to incorporate changes provided that such modification or amendment does not materially increase or decrease benefits provided under the Plan. Any amendment or modification to the Plan shall be effective at such date as the Compensation Committee may determine with respect to any amendment adopted by the Compensation Committee and as the Benefits Committee may determine with respect to any non-material amendment adopted by the Benefits Committee.

(b) The Plan may not be amended, modified, terminated or discontinued during the one (1) year period beginning on the Change Date. In addition, any amendment, modification, plan termination or discontinuance which would reduce the benefits provided under Article 3 will not become effective until six (6) months after adoption and shall be null and void if a Change in Control occurs during such six (6) month period.

(c) Decisions regarding the design of the Plan (including any decision to amend or terminate, or to not amend or terminate the Plan) will be made in a settlor capacity and will not be governed by the fiduciary responsibility provisions of the Employee Retirement Income Security Act of 1974, as amended.

6.4 Management Rights. Participation in the Plan shall not lessen or otherwise affect the responsibility of an Employee to perform fully his duties in a satisfactory and workmanlike manner. This Plan shall not be deemed to constitute a contract between a Participating Company and any Employee or other person whether or not in the employ of the Participating Company, nor shall anything herein contained be deemed to give any Employee or other person whether or not in the employ of a Participating Company any right to be retained in the employ of any Participating Company, or to interfere with the right of any Participating Company to discharge any Employee at any time and to treat him without any regard to the effect which such treatment might have upon him as an Employee covered by the Plan.

6.5 Funding. The Plan shall constitute an unfunded and unsecured obligation of the Participating Companies payable from the general funds of such Participating Companies.

6.6 Withholding of Taxes. Each Participating Company may withhold from any amounts payable under the Plan all federal, state, city and/or other taxes as shall be legally required.

6.7 Participant's Responsibility. Each Participant (or personal representative of a deceased Participant's estate) shall be responsible for providing the Administrative Committee with his current address. Any notices required or permitted to be given hereunder shall be deemed given if directed to such address and mailed by regular United States mail. The Administrative Committee shall not have any obligation or duty to locate a Participant.

6.8 Indemnification. Each Participating Company shall indemnify and hold harmless each member of the Board of Directors, each member of the Benefits Committee, each member of the Administrative Committee and each officer and employee of a Participating Company to whom are delegated duties, responsibilities, and authority with respect to this Plan against all claims, liabilities, fines and penalties, and all expenses reasonably incurred by or imposed upon him (including, but not limited to reasonable attorney fees) which arise as a result of his actions or failure to act in connection with the operation and administration of this Plan to the extent lawfully allowable and to the extent that such claim, liability, fine, penalty, or expense is not paid for by liability insurance purchased or paid for by a Participating Company. Notwithstanding the foregoing, a Participating Company shall not indemnify any person for any such amount incurred through any settlement or compromise of any action unless the Participating Company consents in writing to such settlement or compromise.

6.9 Governing Law. The Plan shall be governed by and construed in accordance with applicable Federal laws, including ERISA, governing employee benefit plans and in accordance with the laws of the State of Oklahoma where such laws are not in conflict with the aforementioned federal laws.

6.10 Right of Recovery. If any Participating Company makes payment(s) in excess of the amount required under the Plan, the Administrative Committee shall have the right to recover the excess payment(s) from any person who received the excess payment(s). Such recovery shall be returned by the Administrative Committee to such Participating Company.

6.11 Adoption by Participating Company. Any Affiliate may adopt or withdraw from this Plan. The adoption resolution may contain such specific changes and variations in this Plan's terms and provisions applicable to the employees of the adopting Participating Company as may be acceptable to the Administrative Committee.

6.12 Code Section 409A. It is intended that this Plan meet the requirements of the short-term deferral exception from Section 409A of the Code and it is recognized that it may be necessary to modify this Plan to reflect guidance under Section 409A of the Code issued by the Internal Revenue Service. The Compensation Committee and the Benefits Committee shall have discretion in determining: (i) whether any modification of the Plan is desirable or appropriate; and (ii) the terms of any such modification.

Notwithstanding any provision to the contrary in this Plan, no payment or distribution under this Plan which constitutes an item of deferred compensation under Section 409A of the Code and becomes payable by reason of a Participant's termination of employment with the Company will be made prior to the earlier of: (i) the expiration of the six (6)-month period measured from the date of his "separation from service" (as such term is defined in Treasury Regulations issued under Code Section 409A); or (ii) the date of his death, if he is deemed at the time of such separation from service to be a "key employee" within the meaning of that term under Code Section 416(i) and such delayed commencement is otherwise required in order to avoid a prohibited distribution under Code Section 409A(a)(2). Upon the expiration of the applicable Code Section 409A(a)(2) deferral period, all payments and benefits deferred pursuant to this Section 6.12 (whether they would have otherwise been payable in a single sum or in installments in the absence of such deferral) shall be paid or reimbursed such key employee in a lump sum, and any remaining payments due under this Plan will be paid in accordance with the normal payment dates specified for them herein.

IN WITNESS WHEREOF, the Company has caused this amended and restated Plan to be executed effective as herein provided.

THE WILLIAMS COMPANIES, INC.

By: s/ Stephanie Cipolla
Title: Vice President Human Resources

CONFIDENTIAL SEPARATION AGREEMENT AND RELEASE

THIS CONFIDENTIAL SEPARATION AGREEMENT AND RELEASE ("Agreement") is entered into this 2nd day of April, 2008, by and between THE WILLIAMS COMPANIES, INC., a Delaware Corporation ("Williams" or the "Company"), and Michael P. Johnson ("Executive");

WHEREAS, Executive has expressed an interest in retiring, effective March 31, 2008 ("Separation Date"); and

WHEREAS, the Company has determined that the continued availability of Executive after his retirement is needed in order to provide an orderly transition of duties to Executive's successor; and

WHEREAS, Executive is willing to provide consulting services after his retirement in accordance with the provisions of this Agreement and the Consulting Agreement, a copy of which is attached hereto as Exhibit "A"; and

WHEREAS, the Company has agreed to provide the Executive with a Separation Payment in exchange for Executive's comprehensive release and agreements concerning, non-disparagement, non-solicitation of Company's employees, and maintaining confidentiality;

NOW, THEREFORE, in consideration of their mutual promises made herein and for other good and valuable consideration, and intending to be legally bound, the Company and Executive hereby agree as follows:

1. Executive Services. Executive and Company agree that, for a period of up to nine (9) months following the Separation Date, to be determined by the Company in its sole and absolute discretion, Executive will provide consulting services to the Company in accordance with the terms of the Consulting Agreement attached hereto as Exhibit "A".

2. Company Payments. In accordance with the Company's normal pay cycle, but not earlier than eight (8) days following Executive's execution of this Agreement, which shall not occur prior to March 31, 2008, the Company shall pay Executive:

a. The sum of Two Hundred Sixty Three Thousand Seven Hundred Fifty Eight Dollars ($263,758.00) ("Consulting Fee") in exchange for Executive executing the

Consulting Agreement set forth on Exhibit "A" and performing the services described therein; and

b. The sum of Five Hundred Thousand Dollars ($500,000.00) ("Separation Payment") in exchange for Executive's covenants and promises contained in this Agreement.

3. Financial Planning Services. As further consideration for the Executive's promises and covenants and promises contained in this Agreement, Williams shall continue to provide Executive with financial planning services utilizing The Ayco Company, L.P. through July 31, 2009.

4. Release. In consideration of the Separation Payment and other benefits provided hereunder, Executive, for himself, his attorneys, and his heirs, executors, administrators, successors and assigns, does hereby fully, finally and forever release and discharge Company and its parent company, subsidiaries, affiliates, predecessors, successors and assigns and their respective officers, directors, employees, representatives, agents and fiduciaries, *de facto* or *de jure* or benefit plans ("Released Parties") of and from any and all charges, claims, actions (in law or in equity), suits, demands, losses, expenses, damages, debts, liabilities, obligations, disputes, proceedings, or any other manner of liability (known or unknown) including without limitation those arising from, in whole or in part, the employment relationship between Company or one of its subsidiaries or affiliates and Executive or the termination thereof which exist, or have heretofore accrued, fixed or contingent, known or unknown, including without limitation any claims arising under Title VII of the Civil Rights Act of 1964 as amended by the Civil Rights Act of 1991, 42 U.S.C. § 2000e, *et seq.*; 42 U.S.C. § 1981; 42 U.S.C. § 1983; 42 U.S.C. § 1985; 42 U.S.C. § 1986; the Equal Pay Act of 1963, 29 U.S.C. § 206(d); the National Labor Relations Act, as amended, 29 U.S.C. § 160, *et seq.*; the Americans With Disabilities Act of 1990, 42 U.S.C. § 12101, *et seq.*; the Employee Retirement Income Security Act of 1974, as amended, ("ERISA"), 29 U.S.C. § 1001,*et seq.* (except that the parties agree that by signing this Agreement, Executive does not waive his rights under any claim for benefits that was or may have been filed prior to the date Executive signed this Agreement); the Age Discrimination in Employment Act of 1967, as amended by the Older Workers Benefit Protection Act of 1990, 29 U.S.C.§ 621, *et seq.*; the Family and Medical Leave Act of 1993, 29 U.S.C.§ 2601 *et seq.*; the Oklahoma Anti-Discrimination Act, Okla. Stat., tit. 25, §§ 1101,*et seq.*, and any claims for

wrongful discharge, defamation, infliction of emotional distress, termination in violation of public policy, retaliatory discharge, including those based on workers' compensation retaliation under state statutes, discrimination on the basis of handicap, or claims arising under any local, state or federal regulation, statute or common law. Executive acknowledges and affirms that this Agreement is in nature and character both general and specific and that the specific descriptions and details hereinafter and hereinabove set forth do not in any manner limit or otherwise affect the general nature and character of this Agreement or the application thereof to Company and Executive. This Agreement does not release or discharge any claim or rights which might arise out of the actions of Company after the date Executive signs this Agreement.

5. Severance. Due to the Executive's voluntary retirement and the Consulting Fee and Separation Payment provided hereunder, Executive also hereby voluntarily waives any right which he may have to receive severance benefits under The Williams Companies Severance Pay Plan or any other severance pay plan, practices, programs, agreements or arrangements maintained by the Company, including, but not limited to, any change-in-control severance plan or agreement.

6. No Release of Vested Benefits or Health and Welfare Benefits. Executive does not, by signing this Agreement, release or discharge any right to any vested, deferred benefit in any qualified employee benefit or incentive plan which provides for retirement, pension, savings, thrift and/or employee stock ownership or any benefit due Executive as a participant in any employee health and welfare plan, as such terms are used under ERISA, maintained by any of the Released Parties which employed Executive. Executive's rights under any such employee benefit or incentive compensation plan shall be governed by the terms of such plan. Furthermore, following the eighth (8th) day after the Separation Date, and in accordance with Company's normal pay cycle, Executive will receive payment for the balance of any accrued and unused Paid Time Off (PTO) for the calendar year 2008. Executive understands and acknowledges that, pursuant to the Company's PTO Policy, Executive will not accrue any additional PTO while performing services as a consultant under the Consulting Agreement.

7. Confidentiality/Company Property. Executive shall keep confidential the existence of this Agreement, its terms, contents, conditions, proceedings and negotiations, he will make no statements or representations relating thereto, except to her attorney or tax advisor, his spouse, or as may otherwise be allowed or required by law. Executive further acknowledges

his continuing obligations to maintain confidentiality of Released Parties' confidential and proprietary information and he shall not, at any time, use for his personal benefit, or disclose, communicate or divulge to, or use for the direct or indirect benefit of any person, firm, association or company other than the Released Parties any confidential information regarding the employees, business methods, business strategies and plans, policies, procedures, techniques, research or development projects or results, trade secrets, or other knowledge or processes of or developed by the Released Parties, including but not limited to, or any other confidential information relating to or dealing with the business operations, employees or activities of Released Parties, made known to Executive or learned or acquired by Executive while in the employ of Company or one of its subsidiaries or affiliates. Executive acknowledges that this Paragraph 7 is a separate agreement, and the Company is granted the right of specific performance to enforce the provisions of this Paragraph 7. The Executive also acknowledges that this Paragraph 7 is a material term of this Agreement and that its breach could result in damage to the Company that may be difficult to ascertain and that upon any such breach or in reasonable anticipation of any such breach, the Company will be entitled to an order of any court of competent jurisdiction to enjoin such breach.

8. <u>Continued Cooperation</u>. Upon reasonable request of Company, Executive shall consult with Company in the orderly transition of business matters in which Executive participated during his active employment with Company and/or with respect to any litigation, legal proceedings or other disputes arising in connection with such business matters, including, but not limited to, matters with respect to Company's response to inquiries initiated by governmental entities or other third parties and defense of certain lawsuits against Company and such other matters as shall be reasonably requested from time to time by Company's General Counsel.

9. <u>Non-solicitation</u>. For a period of twenty-four (24) months following Executive's Separation Date, Executive shall not directly or indirectly induce or attempt to influence any employee of the Released Parties to terminate his or her employment with the Released Parties.

10. <u>Executive's Miscellaneous Covenants</u>. By signing this Agreement, Executive covenants, agrees, represents and warrants that:

(a) The Separation Payment provided hereunder is a benefit to which he is not otherwise entitled under any Company plan, program or prior agreement;

(b) Executive has not filed and will not in the future file any lawsuits, complaints, petitions or accusatory pleadings in a court of law against any of the Released Parties based upon, arising out of or in any way related to any event or events occurring prior to the signing of this Agreement, including, without limitation, his employment with any of the Released Parties or the termination thereof;

(c) This Agreement specifically includes, without limitation, all claims asserted by or on behalf of Executive against any of the Released Parties, together with all claims which might have been asserted by or on behalf of Executive in any suit, claim (known or unknown), or grievance against any of the Released Parties for or on account of any matter or things whatsoever up to and including the date Executive signs this Agreement;

(d) He has not heretofore assigned or transferred, or purported to assign or transfer, to any person or entity, any claim or any portion thereof or interest therein and acknowledges that this Agreement shall be binding upon Executive and upon his heirs, administrators, representatives, executors, successors, and assigns, and shall inure to the benefit of the Released Parties and each of them, and to their heirs, administrators, representatives, executors, successors, and assigns;

(e) Executive waives all rights to recovery for any damages or compensation awarded as a result of any suit or proceeding by any third party or governmental agency on Executive's behalf.

11. Mutual Non-disparagement. Company agrees to refrain from making or publishing any statement critical of Executive or in any way adversely affecting or otherwise maligning Executive's reputation. Executive agrees that he will not make or publish any statement critical of the Released Parties, its affiliates, or their respective executive officers, and directors or in any way adversely affecting or otherwise maligning the business or reputation of any member of the Released Parties.

12. No Admission of Liability. Notwithstanding the provisions of this Agreement and the payments to be made by Company to Executive hereunder, Released Parties do not admit any manner of liability to Executive. This Agreement has been entered into as a means of

settling any and all disputes that have or may have arisen between Released Parties and Executive.

13. No Tax Advice. Executive agrees and acknowledges that the Company has made no representations to him regarding the tax consequences of the money paid pursuant to this Agreement, and that he shall rely upon his own tax advice with respect to any taxes owed on any of such monies. Executive shall be solely responsible for the payment of any federal, state or local taxes owed by Executive as a result of his receipt of money or benefits paid pursuant to this Agreement.

14. Indemnification. Subject to Article VIII of the By-Laws of The Williams Companies, Inc., and to the extent permitted by law, Company will defend and indemnify Executive with regard to claims brought against Executive by third parties and arising from actions taken by Executive in his capacity as an officer and agent of Company.

15. Recovery of Monies Owed to or by the Company. Executive acknowledges and agrees that any monies he owes to Company, Released Parties, or to Company's or Released Parties' vendor(s) contracted to provide business tools or services for use by Executive in his employment, including but not limited to Company credit card debt, relocation repayment obligations or pre-paid Educational Assistance Plan benefits, may be deducted from Executive's Separation Payment. Williams agrees that Executive shall be entitled to reimbursement of any reasonable expenses incurred by Executive in connection with his employment with the Company up through March 31, 2008, provided Executive submits a proper expense report itemizing such expenses no later than April 30, 2008.

16. Opportunity to Consider Agreement and Consult Counsel. Executive acknowledges that this Agreement is a binding legal document, and that he has been advised by Company to consult with an attorney before signing this Agreement. By signing this Agreement, Executive acknowledges that he has been extended a period of twenty-one (21) days within which to consider this Agreement.

17. Revocation Period. For a period of seven (7) days following Executive's execution of the Agreement, Executive may revoke the Agreement by notifying Company, in writing, of his desire to do so. After the seven (7) day period has expired, this Agreement shall become effective and enforceable.

18. Binding Effect. By signing this Agreement, the parties agree and acknowledge that they have carefully read and fully understood the contents of this Agreement, and that this Agreement has been freely signed by the party executing this Agreement. This Agreement is binding upon and shall inure to the benefit of the parties hereto and their respective successors, assigns, personal representatives, officers, directors, agents, attorneys, parents, subsidiaries and affiliates.

19. Entire Agreement. This Agreement constitutes the entire agreement between the parties hereto pertaining to the facts and matters stated herein and supersedes any and all prior understandings, agreements or representations or understandings, whether written or oral, prior to the date hereof; provided, however, that this Agreement shall have no effect on the enforceability of the Consulting Agreement referenced in Paragraph 1 herein and attached hereto as Exhibit "A," or on the enforceability of any prior agreement relating to any covenant not to compete, trade secrets, and/or confidentiality.

20. Governing Law. This Agreement and the rights and obligations hereunder shall be construed in all respects in accordance with the internal laws of the State of Oklahoma without reference to the conflict of laws provisions thereof. Should any provision of this Agreement be found or declared or determined by a court of competent jurisdiction to be invalid, the validity of the remaining parts, terms or provisions shall not be affected thereby and any such invalid part, term or provision shall be deemed not to be a part of this Agreement. Any litigation concerning this Agreement or the facts or matters described herein shall be brought only in a court of competent jurisdiction in Tulsa County, Tulsa, Oklahoma, and the parties hereby waive personal jurisdiction and any objections to venue.

21. Amendment of Agreement. This Agreement may not be modified or amended except by an instrument in writing signed by both Executive and a duly authorized representative of Company.

22. Headings. The heading of paragraphs or subparagraphs herein are included solely for convenience or reference and will not control the meaning or interpretation of any of the provisions of this Agreement.

23. Notices: Any and all notices required to be sent pursuant to the terms of this Agreement will be sent by registered or certified mail or be personally delivered to the parties hereto at the following addresses or such other addresses as they may designate:

Executive:	Michael P. Johnson ____ Tulsa, OK
Company:	The Williams Companies, Inc. Attn: Vice President, Human Resources One William Center P. O. Box 2400 Tulsa, Oklahoma 74102

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day first written above.

THE WILLIAMS COMPANIES, INC.

By: ________________________________

Title: ________________________________

WITNESS:

Michael P. Johnson

ACKNOWLEDGMENT

I HEREBY ACKNOWLEDGE that The Williams Companies, Inc. ("the Company"), in accordance with the Age Discrimination in Employment Act of 1967, as amended by the Older Workers Benefit Protection Act of 1990, informed me in writing that:

(1) I should consult with an attorney before signing the Confidential Separation Agreement and Release ("Agreement") which was provided to me today.

(2) I may review the Agreement for a period of up to twenty-one (21) days prior to signing the Agreement. If I choose to take less than twenty-one (21) days to review the Agreement, I do so knowingly, willingly and on advice of counsel.

(3) For a period of seven (7) days following the signing of the Agreement, I may revoke the Agreement, and that the Agreement will not become effective or enforceable until the seven day revocation period has elapsed; and

(4) The Consulting Fee and Separation Payment described in Paragraph 2 of this Agreement will be paid in accordance with the Company's normal pay cycle, but will not be paid to me until the seven-day revocation period has elapsed.

I HEREBY FURTHER ACKNOWLEDGE receipt of this Confidential Separation Agreement and Release on the__________ day of ____________________, 2008.

WITNESS:

______________________________ ______________________________

Michael P. Johnson

EXHIBIT “A”

CONSULTING AGREEMENT

THIS CONSULTING AGREEMENT is entered into this 2nd day of April, 2008, by and between THE WILLIAMS COMPANIES, INC. a Delaware Corporation, (“Williams” or the “Company”) and Michael P. Johnson (“Consultant”).

WHEREAS, Williams wishes to avail itself of Consultant’s knowledge, expertise and experience by utilizing the services of Consultant; and

WHEREAS, Consultant is willing to serve as a consultant to Williams upon the terms and conditions set forth below;

NOW, THEREFORE, in consideration of their mutual promises and for other good and valuable consideration, Williams and Consultant hereby agree as follows:

1. Consulting Services.

(a) During the period beginning on the date on which Consultant ceases to be employed by Williams and continuing through December 31, 2008 (the “Consulting Period”), Consultant shall provide to Williams, including its subsidiaries and affiliates, consulting services commensurate with his status and experience as Williams’ Senior Vice President and Chief Administrative Officer to enable a smooth transition of his duties to his successor with respect to such matters as shall be reasonably requested from time to time by the Chief Executive Officer of Williams (the “Williams Representative”), provided that Consultant shall not be required to provide such services during any period when he is unable to perform due to his health.

(b) Consultant shall provide consulting services to Williams only as needed and when reasonably requested by the Williams Representative, provided that, without his prior consent, Consultant shall not be required to devote more than eighty (80) hours in any calendar month to the performance of any consulting services hereunder. Consultant agrees that in the event it becomes necessary for him to devote more than eighty (80) hours in any calendar month to performing services under this Agreement, Consultant will obtain approval from Williams’ Chief Executive Officer and the Executive Officer Team member for whom the services are being provided prior to providing such services. Consultant shall determine the time and location at which he shall perform such services, subject to the right of the Williams Representative to reasonably request by advance written notice that such services be performed at a specific time and at a specific location. Consultant shall honor any such request unless he is unable to perform due to his health, or he has a conflicting business commitment that would preclude him from performing such services at the time and/or place requested by the Williams Representative, and in such circumstances, shall make reasonable efforts to arrange a mutually satisfactory alternative. Williams shall use its reasonable best efforts not to require the performance of consulting services in any manner that unreasonably interferes with any other business activity of Consultant.

(c) Consultant shall not, solely by virtue of the consulting services provided hereunder, be considered to be an officer or employee of any member of Williams during the Consulting Period, and shall not have the power or authority to contract in the name of or bind any member of Williams. Consultant shall at all times be treated as an independent contractor and shall be responsible for the payment of all taxes with respect to all amounts paid to him hereunder. Consultant shall not, by reason of the services performed hereunder, be entitled to participate in any employee benefits plan, program or arrangement made available to any employee of Williams.

(d) This Agreement is personal to Consultant and all of the services required of Consultant hereunder shall be performed personally by him.

2. Consulting Fees. In accordance with its normal pay cycle, but not before the eighth (8h) day following Consultant's execution of this Agreement, Williams shall pay Consultant the sum of Two Hundred Sixty Three Thousand Seven Hundred Fifty Eight Dollars ($263,758.00) ("Consulting Fee") as consideration for executing this Agreement and providing the services set forth hereunder. Consultant shall not be entitled to receive any other compensation, bonuses or benefits provided to Williams' employees in exchange for the services provided by Consultant under the terms of this Agreement. However, Williams will reimburse Consultant for reasonable and necessary travel expenses, including costs for transportation, meals and lodging that Consultant may incur in connection with his performance of services under this Agreement. During the Consulting Period, Consultant may also utilize Williams' corporate aircraft for travel necessary to his performance of services under this Agreement, subject to the approval of the Williams Representative and the availability of the aircraft.

3. Confidential Information. Consultant shall not, at any time during the Consulting Period, make use of or disclose, directly or indirectly, any (i) trade secret or other confidential or

secret information of Williams or (ii) other technical, business, proprietary or financial information of Williams not available to the public generally or to the competitors of Williams ("Confidential Information"), except to the extent that such Confidential Information (a) becomes a matter of public record or is published in a newspaper, magazine or other periodical available to the general public, other than as a result of any act or omission of Consultant, (b) is required to be disclosed by any law, regulation or order of any court or regulatory commission, department or agency, provided that Consultant gives prompt notice of such requirement to Williams to enable Williams to seek an appropriate protective order, or (c) is necessary to perform properly Consultant's duties under this Agreement. Promptly following the termination of the Consulting Period, Consultant shall surrender to Williams all records, memoranda, notes, plans, reports, computer tapes and software and other documents and data which constitute Confidential Information which he may then possess or have under his control (together with all copies thereof).

4. Exclusive Services/Non-solicitation.

(a) Consultant acknowledges that during the Consulting Period he will become familiar with trade secrets and other confidential information concerning Williams and that his services will be of special, unique and extraordinary value to Williams.

(b) Consultant agrees that during the Consulting Period he shall not in any manner, directly or indirectly, through any person, firm or corporation, alone or as a member of a partnership or as an officer, director, stockholder, investor or employee of or consultant to any other corporation or enterprise or otherwise, engage or be engaged, or assist any other person, firm corporation or enterprise in engaging or being engaged, in any business, in which Consultant was involved or of which he has knowledge is being conducted by Williams during the Consulting Period. Notwithstanding the provisions of this subparagraph 4(b) to the contrary, Consultant may act as a director, stockholder, investor or employee of or consultant to any corporation or enterprise with regard to the business or businesses referred to above with the prior written consent of Williams, such consent not to be unreasonably withheld.

(c) Consultant further agrees that during the Consulting Period he shall not in any manner, directly or indirectly, induce or attempt to induce any employee Williams to terminate or abandon his or her employment for any purpose whatsoever.

(d) Nothing in this Paragraph 4 shall prohibit Consultant from being (i) a stockholder in a mutual fund or a diversified investment company or (ii) a passive owner of not more than two percent (2%) of the outstanding stock of any class of a corporation, or any securities of which are publicly traded, so long as Consultant has no active participation in the business of such corporation.

(e) If, at any time of enforcement of this Paragraph 4, a court holds that the restrictions stated herein are unreasonable under circumstances then existing, the parties hereto agree that the maximum period, scope or geographical area reasonable under such circumstances shall be substituted for the stated period, scope or area and that the court shall be allowed to revise the restrictions contained herein to cover the maximum period, scope and area permitted by law. This Agreement shall not authorize a court to increase or broaden any of the restrictions in this Paragraph.

5. Hold Harmless. Consultant shall hold harmless Williams, its subsidiaries and affiliates, and its and their respective shareholders, officers, directors, employees and attorneys

against any damage, injury, death, claim, loss, charge or expense (including, without limitation, attorneys' fees and court costs and the costs of investigation) of any party, including Consultant, arising out of or relating to, or claimed to arise out of or relate to, Consultant's gross negligence or willful misconduct in performing under this Agreement.

6. No Tax Advice. Consultant agrees and acknowledges that Williams has made no representations to him regarding the tax consequences of the money paid pursuant to this Agreement, and that he shall rely upon his own tax advice with respect to any taxes owed on any of such monies. Consultant shall be solely responsible for the payment of any federal, state or local taxes owed by Consultant as a result of his receipt of money or benefits provided to him by Williams pursuant to this Agreement.

7. Termination of the Consulting Services. Williams may terminate this Agreement at any time prior to December 31, 2008, but the parties agree and acknowledge that Williams shall only be entitled to a pro-rata refund of the Consulting Fee in the event that the Agreement is terminated solely for cause, which shall be limited to either (i) the conviction of Consultant of a felony which has a substantial effect on Williams' business or reputation, or (ii) the continual and repeated failure of Consultant to perform the services required of him hereunder, after written notice of the alleged failures and an opportunity to cure has been given. Consultant may only terminate this Agreement due to a material breach hereof by Williams.

8. No Waiver of Vested Benefits. Nothing in this Agreement shall be construed to limit, reduce, offset or otherwise impair Consultant's rights to any benefits or compensation vested or accrued under the terms of the employee benefit plans, programs or arrangements maintained by Williams other than those benefits that were released or waived by Consultant pursuant to the Confidential Separation Agreement and Release dated April 2, 2008.

9. Computer/Office Support and Access. During the Consulting Period, Williams shall provide Consultant with office space at Williams' principal place of business, which will include telephone and computer access and administrative support. In addition, Williams shall provide and maintain Consultant's computer and access to Williams' network and telephone systems via his home office as shall be reasonably necessary for Consultant to provide the consulting services requested by Williams during the Consulting Period and under the terms of this Agreement. At the termination of the Consulting Period, Consultant shall return all of Williams' property within his possession to Williams.

10. Enforcement. The parties hereto agree that Williams would be damaged irreparably in the event that any provision of Paragraph 3 or 4 of this Agreement were not performed in accordance with its terms or were otherwise breached and that money damages would be an inadequate remedy for any such nonperformance or breach. Accordingly, Williams and its successors and permitted assigns shall be entitled, in addition to other rights and remedies existing in their favor, to an injunction or injunctions to prevent any breach or threatened breach of any of such provisions and to enforce such provisions specifically (without posting a bond or other security). Consultant agrees any litigation concerning this Agreement or the facts or matters described herein shall be brought only in a court of competent jurisdiction in Tulsa County, Tulsa, Oklahoma, and Consultant agrees that he will submit himself to the personal jurisdiction of the courts of the State of Oklahoma in any action by Williams to enforce the terms of this Agreement or to obtain injunctive or other relief.

11. Miscellaneous. This Agreement may only be amended by a written instrument signed by Williams and Consultant. Except as otherwise expressly provided hereunder, this Agreement shall constitute the entire agreement between Williams and Consultant with respect

to the subject matter hereof The parties further agree and acknowledge that this Agreement constitutes the entire agreement between the parties hereto pertaining to the facts and matters stated herein and supersedes any and all prior understandings, agreements or representations or understandings, whether written or oral, prior to the date hereof; provided, however, that this Agreement shall have no effect on the enforceability or terms of the Confidential Separation Agreement and Release dated April 2, 2008, or on the enforceability of any prior agreement relating to non-solicitation, trade secrets, and/or confidentiality. This Agreement may be executed in counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

12. Notices. Any and all notices required to be sent pursuant to the terms of this Agreement will be sent by registered or certified mail, or be personally delivered to the parties hereto at the following addresses, or such other addresses as they may designate:

Consultant:	Michael P. Johnson ____________________ Tulsa, OK
Company:	The Williams Companies, Inc. Attn: Vice President, Human Resources One William Center P. O. Box 2400 Tulsa, Oklahoma 74102

13. Successor and Assigns. This Agreement shall be enforceable by Consultant and his heirs, executors, administrators and legal representatives, and by Williams and its successors and assigns.

14. Survival. Paragraphs 3, 4, and 10 of this Agreement shall survive and continue in full force and effect in accordance with their respective terms, notwithstanding any termination of the Consulting Period.

15. Governing Law. This Agreement shall be governed by the laws of the State of Oklahoma, without reference to the principles of conflicts of law.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day first written above.

THE WILLIAMS COMPANIES, INC.

By: ______________________________

Title: ______________________________

WITNESS:

______________________________ ______________________________

Michael P. Johnson

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2007	2006	2005	2004
			(Dollars in millions)		
Earnings:					
Income from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 2,047	$ 1,371	$ 558	$ 774	$ 299
Minority interest in income of consolidated subsidiaries	174	90	40	26	21
Less: Equity earnings, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	(61)	(60)	(99)	(66)	(50)
Income from continuing operations before income taxes and cumulative effect of change in accounting principles, minority interest in income of consolidated subsidiaries and equity earnings	2,160	1,401	499	734	270
Add:					
Fixed charges:					
Interest accrued, including proportionate share from 50% owned investees and unconsolidated majority-owned investee (a)	675	709	694	680	822
Rental expense representative of interest factor	21	22	16	19	18
Total fixed charges	696	731	710	699	840
Distributed income of equity-method investees, excluding proportionate share from 50% owned investees and unconsolidated majority-owned investee	53	48	113	108	61
Less:					
Capitalized interest	(59)	(32)	(17)	(7)	(7)
Total earnings as adjusted	$ 2,850	$ 2,148	$ 1,305	$ 1,534	$ 1,164
Fixed charges	$ 696	$ 731	$ 710	$ 699	$ 840
Ratio of earnings to fixed charges	4.09	2.94	1.84	2.19	1.39

(a) Does not include interest related to income taxes, including interest related to FIN 48 liabilities, which is included in *provision for income taxes* on our Consolidated Statement of Income. See Note 5 of Notes to Consolidated Financial Statements.

Exhibit 21

ENTITY	JURISDICTION
ACCROVEN SRL	Barbados
Alliance Canada Marketing L.P.	Alberta
Alliance Canada Marketing LTD	Alberta
Apco Argentina, Inc.	Cayman Islands
Apco Argentina, S.A.	Argentina
Apco Properties Ltd.	Cayman Islands
Arctic Fox Assets, Inc.	Delaware
Aspen Products Pipeline LLC	Delaware
Aux Sable Liquid Products Inc.	Delaware
Aux Sable Liquid Products LP	Alberta
Bargath Inc.	Colorado
Barrett Fuels Corporation	Delaware
Barrett Resources International Corporation	Delaware
Baton Rouge Fractionators LLC	Delaware
Baton Rouge Pipeline LLC	Delaware
Beech Grove Processing Company	Tennessee
Bison Royalty LLC	Delaware
Black Marlin Pipeline Company	Texas
Carbon County UCG, Inc.	Delaware
Carbonate Trend Pipeline LLC	Delaware
Cardinal Operating Company, LLC	Delaware
Cardinal Pipeline Company, LLC	North Carolina
Castle Associates, L.P.	Delaware
ChoiceSeat, L.L.C.	Delaware
Diamond Elk, LLC	Colorado
Discovery Gas Transmission LLC	Delaware
Discovery Producer Services LLC	Delaware
Distributed Power Solutions L.L.C.	Delaware
Eagle Gas Services, Inc.	Ohio
ESPAGAS USA, Inc.	Delaware
F T & T, Inc.	Delaware
Fishhawk Ranch, Inc.	Florida
FleetOne Inc.	Delaware
Fort Union Gas Gathering, L.L.C.	Delaware
Garrison, L.L.C.	Delaware
Goebel Gathering Company, L.L.C.	Delaware
Gulf Liquids Holdings LLC	Delaware
Gulf Liquids New River Project LLC	Delaware
Gulf Star Deepwater Services, LLC	Delaware
Gulfstream Management & Operating Services, L.L.C.	Delaware
Gulfstream Natural Gas System, L.L.C.	Delaware

ENTITY	JURISDICTION
HI-BOL Pipeline Company	Delaware
Inland Ports, Inc.	Tennessee
Laughton, L.L.C.	Delaware
Liberty Operating Company	Delaware
Longhorn Enterprises of Texas, Inc.	Delaware
MAPCO Alaska Inc.	Alaska
MAPCO Inc.	Delaware
Marsh Resources, LLC	Delaware
Mid-Continent Fractionation and Storage, LLC	Delaware
Millennium Energy Fund, L.L.C.	Delaware
Mockingbird Pipeline, L.P.	Delaware
Northwest Argentina Corporation	Utah
Northwest Land Company	Delaware
Northwest Pipeline GP	Delaware
Northwest Pipeline Services LLC	Delaware
Pacific Connector Gas Pipeline, LLC	Delaware
Pacific Connector Gas Pipeline, LP	Delaware
Parachute Pipeline LLC	Delaware
Parkco Two, L.L.C.	Oklahoma
Pine Needle LNG Company, LLC	North Carolina
Pine Needle Operating Company, LLC	Delaware
Rainbow Resources, Inc.	Colorado
Reserveco Inc.	Delaware
Snow Goose Associates, L.L.C.	Delaware
Sociedad Williams Enbridge y Compania	Venezuela
SPV, L.L.C.	Oklahoma
TXG Gas Marketing Company	Delaware
Tennessee Processing Company	Delaware
The Tennessee Coal Company	Delaware
The Williams Companies, International Holdings B.V.	Dutch BV
Thermogas Energy, LLC	Delaware
Touchstar Energy Technologies, Inc.	Texas
Touchstar Technologies Pty Ltd.	South Africa
TransCardinal Company, LLC	Delaware
TransCarolina LNG Company, LLC	Delaware
Transco Coal Gas Company	Delaware
Transco Energy Company, LLC	Delaware
Transco Exploration Company	Delaware
Transco Gas Company, LLC	Delaware
Transco Liberty Pipeline Company	Delaware
Transco P-S Company	Delaware
Transco Resources, Inc.	Delaware
Transco Services LLC	Delaware
Transcontinental Gas Pipe Line Company, LLC	Delaware
Transeastern Gas Pipeline Company, Inc.	Delaware
Tulsa Williams Company	Delaware

ENTITY	JURISDICTION
Valley View Coal, Inc.	Tennessee
Volunteer — Williams, L.L.C.	Delaware
WEM&T Trading GmbH	Austria
WFS — Liquids Company	Delaware
WFS — Pipeline Company	Delaware
WFS Enterprises, Inc.	Delaware
WFS Gathering Company, L.L.C.	Delaware
WGP Development, LLC	Delaware
WGP Enterprises, Inc.	Delaware
WGP Gulfstream Pipeline Company, L.L.C.	Delaware
WGP International Canada, Inc.	New Brunswick
WGPC Holdings LLC	Delaware
WPX Enterprises, Inc.	Delaware
WPX Gas Resources Company	Delaware
Wamsutter LLC	Delaware
Wilgath LLC	Delaware
Williams Acquisition Holding Company, Inc. (Del)	Delaware
Williams Acquisition Holding Company, Inc. (NJ)	New Jersey
Williams Acquisition Holding Company LLC	Delaware
Williams Aircraft, Inc.	Delaware
Williams Alaska Petroleum, Inc.	Alaska
Williams Alliance Canada Marketing, Inc.	New Brunswick
Williams Arkoma Gathering Company, LLC	Delaware
Williams Barnett Gathering System, LP	Texas
Williams Cove Point, Inc.	Delaware
Williams Discovery Pipeline, LLC	Delaware
Williams Distributed Power Services, Inc.	Delaware
Williams Energy Canada, Inc.	New Brunswick
Williams Energy European Services Ltd.	United Kingdom
Williams Energy Marketing & Trading Canada, Inc.	New Brunswick
Williams Energy Marketing & Trading Europe Ltd	England
Williams Energy Marketing & Trading Holdings UK Ltd.	United Kingdom
Williams Energy Services, LLC	Delaware
Williams Energy Solutions, Inc.	Delaware
Williams Energy, L.L.C.	Delaware
Williams Equities, Inc.	Delaware
Williams Exploration Company	Delaware
Williams Express, Inc. (AK)	Alaska
Williams Express, Inc.	Delaware
Williams Fertilizer, Inc.	Delaware
Williams Field Services — Gulf Coast Company, L.P.	Delaware
Williams Field Services Company, LLC	Delaware
Williams Field Services Group, LLC	Delaware
Williams Flexible Generation, LLC	Delaware
Williams Four Corners, LLC	Delaware
Williams GP LLC	Delaware

ENTITY	JURISDICTION
Williams Gas Marketing, Inc.	Delaware
Williams Gas Pipeline Company, LLC	Delaware
Williams Gas Processing — Gulf Coast Company, L.P.	Delaware
Williams Global Energy Cayman Limited	Cayman Islands
Williams Global Holdings Company	Delaware
Williams GmbH	Austria
Williams Gulf Coast Gathering Company, LLC	Delaware
Williams Headquarters Building Company	Delaware
Williams Headquarters Building, L.L.C.	Delaware
Williams Holdings GmbH	Austria
Williams Indonesia, L.L.C.	Delaware
Williams Information Technology, Inc.	Delaware
Williams International Bermuda Limited	Bermuda
Williams International Company	Delaware
Williams International El Furrial Limited	Cayman Islands
Williams International Investments Cayman Limited	Cayman Islands
Williams International Jose Limited	Cayman Islands
Williams International Oil & Gas Venezuela Limited	Cayman Islands
Williams International Pigap Limited	Cayman Islands
Williams International Services Company	Nevada
Williams International Telecom Limited	Delaware
Williams International Telecommunications	Cayman Islands
Williams International Venezuela Limited	Cayman Islands
Williams Learning Center, Inc.	Delaware
Williams Longhorn Holdings, LLC	Delaware
Williams Memphis Terminal, Inc.	Delaware
Williams Merchant Services Company, Inc.	Delaware
Williams Mid-South Pipelines, LLC	Delaware
Williams Midstream Natural Gas Liquids, Inc.	Delaware
Williams Mobile Bay Producer Services, L.L.C.	Delaware
Williams NGL Marketing, LLC	Delaware
Williams Natural Gas Liquids Canada, Inc.	Alberta
Williams Natural Gas Liquids, Inc.	Delaware
Williams New Soda, Inc.	Delaware
Williams Oil Gathering, L.L.C.	Delaware
Williams Olefins Feedstock Pipelines, L.L.C.	Delaware
Williams Olefins, L.L.C.	Delaware
Williams One-Call Services, Inc.	Delaware
Williams Pacific Connector Gas Operator, LLC	Delaware
Williams Pacific Connector Gas Pipeline, LLC	Delaware
Williams Partners Finance Corporation	Delaware
Williams Partners GP LLC	Delaware
Williams Partners Holdings LLC	Delaware
Williams Partners, L.P.	Delaware
Williams Partners Operating LLC	Delaware
Williams PERK, LLC	

ENTITY	JURISDICTION
WILLIAMS PETROLEOS ESPAÑA, S.L.	Spain
Williams Petroleum Pipeline Systems, Inc.	Delaware
Williams Petroleum Services, LLC	Delaware
Williams Pipeline GP LLC	Delaware
Williams Pipeline Operating LLC	Delaware
Williams Pipeline Partners Holdings LLC	Delaware
Williams Pipeline Partners L.P.	Delaware
Williams Pipeline Services Company	Delaware
Williams Production — Gulf Coast Company, L.P.	Delaware
Williams Production Company, LLC	Delaware
Williams Production Holdings LLC	Delaware
Williams Production Mid-Continent Company	Oklahoma
Williams Production RMT Company	Delaware
Williams Production Rocky Mountain Company	Delaware
Williams Production Ryan Gulch LLC	Delaware
Williams Refining & Marketing, L.L.C.	Delaware
Williams Relocation Management, Inc.	Delaware
Williams Resource Center, L.L.C.	Delaware
Williams Soda Holdings, LLC	Delaware
Williams Sodium Products Company	Delaware
Williams Strategic Sourcing Company	Delaware
Williams TravelCenters, Inc.	Delaware
Williams Unita Gathering, LLC	Delaware
Williams Underground Gas Storage Company	Delaware
Williams WPC — I, Inc.	Delaware
Williams WPC — II, Inc.	Delaware
Williams WPC International Company	Delaware
Williams Western Holding Company, Inc.	Delaware
WilPro Energy Services El Furrial Limited	Cayman Islands
WilPro Energy Services Pigap II Limited	Cayman Islands

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following registration statements on Form S-3 and related prospectuses of The Williams Companies, Inc. and in the following registration statements on Form S-8 of our reports dated February 23, 2009, with respect to the consolidated financial statements and schedule of The Williams Companies, Inc. and the effectiveness of internal control over financial reporting of The Williams Companies, Inc., included in this Annual Report (Form 10-K) for the year ended December 31, 2008:

Form S-3:

Registration Statement Nos. 333-29185, 333-106504, and 333-134293

Form S-8:

Registration No. 33-58671 — The Williams Companies, Inc. Stock Plan for Nonofficer Employees

Registration No. 333-03957 — The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors

Registration No. 333-11151 — The Williams Companies, Inc. 1996 Stock Plan

Registration No. 333-40721 — The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-51994 — The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees

Registration No. 333-85542 — The Williams Investment Plus Plan

Registration No. 333-85546 — The Williams Companies, Inc. 2002 Incentive Plan

Registration No. 333-142985 — The Williams Companies, Inc. Employee Stock Purchase Plan

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 23, 2009

NSA Netherland, Sewell
& Associates, Inc.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our audit letters as of December 31, 2008, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2008. We also consent to the reference to us as experts in such Annual Report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C. H. (Scott) Rees III, P.E.
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 17 2009

Exhibit 23.3

Miller and Lents, Ltd.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the incorporation by reference to our reserve reports dated as of December 31, 2008, 2007, and 2006, each of which is included in the Annual Report on Form 10-K of The Williams Companies for the year ended December 31, 2008. We also consent to the reference to Miller and Lents, Ltd. under the heading of "Experts" in such Annual Report.

MILLER AND LENTS, LTD.

By: /s/ Stephen M. Hamburg
Stephen M. Hamburg
Vice President

Houston, Texas
February 15, 2009

EXHIBIT 24

THE WILLIAMS COMPANIES, INC.

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that each of the undersigned individuals, in their capacity as a director or officer, or both, as hereinafter set forth below their signature, of THE WILLIAMS COMPANIES, INC., a Delaware corporation (“Williams”), does hereby constitute and appoint JAMES J. BENDER and LA FLEUR C. BROWNE their true and lawful attorneys and each of them (with full power to act without the others) their true and lawful attorneys for them and in their name and in their capacity as a director or officer, or both, of Williams, as hereinafter set forth below their signature, to sign Williams’ Annual Report to the Securities and Exchange Commission on Form 10-K for the fiscal year ended December 31, 2008, and any and all amendments thereto or all instruments necessary or incidental in connection therewith; and

THAT the undersigned Williams does hereby constitute and appoint JAMES J. BENDER and LA FLEUR C. BROWNE its true and lawful attorneys and each of them (with full power to act without the others) its true and lawful attorney for it and in its name and on its behalf to sign said Form 10-K and any and all amendments thereto and any and all instruments necessary or incidental in connection therewith.

Each of said attorneys shall have full power of substitution and resubstitution, and said attorneys or any of them or any substitute appointed by any of them hereunder shall have full power and authority to do and perform in the name and on behalf of each of the undersigned, in any and all capacities, every act whatsoever requisite or necessary to be done in the premises, as fully to all intents and purposes as each of the undersigned might or could do in person, the undersigned hereby ratifying and approving the acts of said attorneys or any of them or of any such substitute pursuant hereto.

IN WITNESS WHEREOF, the undersigned have executed this instrument, all as of the 22nd day of January, 2009.

/s/ Steven J. Malcolm	/s/ Donald R. Chappel
Steven J. Malcolm Chairman of the Board President and Chief Executive Officer (Principal Executive Officer)	Donald R. Chappel Senior Vice President and Chief Financial Officer (Principal Financial Officer) (Principal Accounting Officer)

/s/ Ted T. Timmermans

Ted T. Timmermans
Controller
(Principal Accounting Officer)

/s/ Joseph R. Cleveland
Joseph R. Cleveland
Director

/s/Irl F. Engelhardt
Irl F. Engelhardt
Director

/s/ William E. Green
William E. Green
Director

/s/ W. R. Howell
W. R. Howell
Director

/s/ George A. Lorch
George A. Lorch
Director

/s/ Frank T. MacInnis
Frank T. MacInnnis
Director

/s/ Kathleen B. Cooper
Kathleen B. Cooper
Director

/s/ William R. Granberry
William R. Granberry
Director

/s/ Juanita H. Hinshaw
Juanita H. Hinshaw
Director

/s/ Charles M. Lillis
Charles M. Lillis
Director

/s/ William G. Lowrie
William G. Lowrie
Director

/s/ Janice D. Stoney
Janice D. Stoney
Director

THE WILLIAMS COMPANIES, INC.

By: /s/ James J. Bender
James J. Bender
Senior Vice President

ATTEST:

/s/ La Fleur C. Browne
La Fleur C. Browne
Secretary

Exhibit 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Steven J. Malcolm
Steven J. Malcolm
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this annual report on Form 10-K of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2009

/s/ Donald R. Chappel
Donald R. Chappel
Senior Vice President
and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of The Williams Companies, Inc. (the “Company”) on Form 10-K for the period ending December 31, 2008 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm

Steven J. Malcolm
Chief Executive Officer
February 24, 2009

/s/ Donald R. Chappel

Donald R. Chappel
Chief Financial Officer

February 24, 2009

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.