WILLIAMS COMPANIES INC
Form 10-K
February 28, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

Form 10-K

(Mark One)

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

or

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

Commission file number 1-4174
The Williams Companies, Inc.
(Exact name of Registrant as Specified in Its Charter)

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant s most recently completed second quarter was approximately $13,912,313,182.

The number of shares outstanding of the registrant s common stock outstanding at February 22, 2007 was 597,861,925.

DOCUMENTS INCORPORATED BY REFERENCE

Document	Parts Into Which Incorporated
Proxy Statement for the Annual Meeting of Stockholders to be held May 17, 2007 (Proxy Statement)	Part III

THE WILLIAMS COMPANIES, INC.
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PART IV

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DEFINITIONS

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

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

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.

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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 450 Fifth Street, N.W., 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 Secretary at Williams, 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.

We continue to use 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.

Today, we primarily find, produce, gather, process and transport natural gas. We also manage a wholesale power business. Our operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard.

In 2006 we focused on continued disciplined growth. During 2006 we:

Continued to improve both EVA® and segment profit;

Invested in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position;

Continued to increase natural gas production in a responsible manner;

Accelerated additional asset transactions between us and Williams Partners L.P., our master limited partnership;

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

Increased the scale of our gathering and processing business in key growth basins;

Filed new rates to enable our Gas Pipeline segment to remain competitive and value-creating, and completed a capacity replacement project;

Executed power contracts that reduce risk while adding new business and strengthening future cash flow potential.

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

2006 HIGHLIGHTS

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 approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

In April 2006, Transcontinental Gas Pipe Line Corporation (Transco) issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Transco completed an offer to exchange all of these notes for substantially identical notes registered under the Securities Act of 1933, as amended.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In May 2006, we replaced our $1.275 billion secured revolving credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and financial covenants as the secured facility, but contains certain additional restrictions. (See Note 11 of Notes to Consolidated Financial Statements.)

In May 2006, our Board of Directors approved a regular quarterly dividend of 9 cents per share of common stock, which reflects an increase of 20 percent compared with the 7.5 cents per share paid in each of the three prior quarters.

In June 2006, Northwest Pipeline Corporation (Northwest Pipeline) issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Northwest Pipeline Corporation completed an offer to exchange all of these notes for substantially identical notes registered under the Securities Act of 1933, as amended.

In June 2006, we reached an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000, and July 22, 2002, for a total payment of $290 million to plaintiffs. We funded our $145 million portion of the settlement with cash-on-hand in November 2006, with the balance funded through insurance proceeds. We recorded a pre-tax charge for approximately $161 million in second-quarter 2006. This settlement did not have a material effect on our liquidity position. (See Note 15 of Notes to Consolidated Financial Statements.)

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

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On July 31, 2006, and August 1, 2006, we received a verdict in civil litigation related to a contractual dispute surrounding certain natural gas processing facilities known as Gulf Liquids. We recorded a pre-tax charge for approximately $88 million in second quarter 2006 related to this loss contingency. (See Note 15 of Notes to Consolidated Financial Statements.)

Northwest Pipeline and Transco have each filed a general rate case with the Federal Energy Regulatory Commission (FERC). Northwest Pipeline reached a settlement in its pending rate case. The settlement is subject to FERC approval, which is expected by mid-2007. The new transportation and storage rates for both pipelines will be effective, subject to refund, in the first quarter of 2007.

In December 2006, Northwest Pipeline completed and placed into service its capacity replacement project in the state of Washington. The project involved abandoning 268 miles of 26-inch pipeline and replacing it with approximately 80 miles of 36-inch pipeline constructed in four sections along the same pipeline corridor. Additionally, Northwest Pipeline modified five existing compressor stations which created additional net horsepower.

Our property insurance coverage levels and premiums were revised during the second quarter of 2006. In general, our coverage levels have decreased while our premiums have increased. These changes reflect general trends in our industry due to hurricane-related damages in recent years.

FINANCIAL INFORMATION ABOUT SEGMENTS

See Note 17 of our Notes to Consolidated Financial Statements for information with respect to each segment s revenues, profits or losses and total assets. See Note 9 for information with respect to property, plant and equipment for each segment.

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.

Gas Pipeline includes our interstate natural gas pipelines and pipeline joint venture investments organized under our wholly owned subsidiary, Williams Gas Pipeline Company, LLC.

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., our master limited partnership formed in 2005.

Power manages our wholesale power and natural gas commodity businesses through purchases, sales and other related transactions, under our wholly owned subsidiary Williams Power Company, Inc. and its subsidiaries.

Other primarily consists of corporate operations. Other also includes our interest in Longhorn Partners Pipeline, L.P. (Longhorn).

This report is organized to reflect this structure.

Detailed discussion of each of our business segments follows.

Exploration & Production

Our Exploration & Production segment, which is comprised of several wholly owned and partially owned subsidiaries, including Williams Production Company LLC and Williams Production RMT Company (RMT), 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 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. (Apco Argentina), an oil and gas exploration and production company with operations in Argentina, and a four percent 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 primary strategy is to utilize its expertise in the development of tight-sands, shale, and coal bed methane reserves. 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 comprise over 47 percent of proved reserves and to drill in areas of probable 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 prices at December 31 held constant) for the year indicated:

	2006	**2005**	**2004**
		(Bcfe)	
Proved developed natural gas reserves	1,945	1,643	1,348
Proved undeveloped natural gas reserves	1,756	1,739	1,638
Total proved natural gas reserves	3,701	3,382	2,986

The following table summarizes our proved natural gas reserves by basin as of December 31, 2006:

Basin	**Percentage of Proved Reserves**
Piceance	67%
San Juan	17%
Powder River	10%

Other	6%
	100%

No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year-end 2006. 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 filed any information with respect to its estimated total reserves at December 31, 2006, with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable due to special DOE reporting requirements, such as the requirement to report gross operated reserves only. The underlying estimated reserves for the DOE did not differ by more than five percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

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Approximately 98 percent of our year-end 2006 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, 2006 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. Reserves estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust which comprise another approximately two percent of our total U.S. proved reserves were prepared by Miller and Lents, LTD.

Oil and gas properties

Following is a discussion of our oil and gas properties for our significant areas.

Piceance basin

The Piceance basin is located in northwestern Colorado. In 2006, we drilled 494 gross wells of which we operate 477, and owned working interests in a total of 1,889 gross producing wells at year-end. We produced a net of approximately 152 Bcfe of natural gas from the Piceance basin during 2006. Our estimated proved reserves in this basin at year-end 2006 were 2,469 Bcfe. The Piceance basin is our largest area of concentrated development comprising approximately 67 percent of our proved reserves at December 31, 2006. This area has approximately 1,500 undrilled proved locations in inventory. Within this basin, we are also the owner and operator of a natural gas gathering and processing system. In March 2005 we entered into a contract with Helmerich & Payne for the operation of 10 new FlexRig® drilling rigs, each for a term of three years. By December 2006, all 10 of these rigs were operating in the Piceance basin. We also have 15 rigs operating in the Piceance basin under contract with other vendors, for a total of 25 rigs operating in the Piceance basin by December 2006.

San Juan basin

The San Juan basin is located in northwest New Mexico and southwest Colorado. In 2006, we participated in the drilling of 214 gross wells, of which we operate 56 and owned working interests in a total of 2,864 gross producing wells at year-end. We produced a net of approximately 56 Bcfe of natural gas from the San Juan basin during 2006. Our estimated proved reserves in the San Juan basin at year-end 2006 were 614 Bcfe.

Powder River basin

The Powder River basin is located in northeast Wyoming. In 2006, we drilled 858 gross wells of which we operate 449, and owned working interests in a total of 4,454 gross producing wells at year-end. We produced a net of approximately 52 Bcfe of natural gas from the Powder River basin during 2006. Our estimated proved reserves in this basin at year-end 2006 were 372 Bcfe. The Powder River basin comprises approximately 10 percent of our proved reserves at December 31, 2006. 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. In 2006, we drilled 112 gross wells, of which we operate 61 and owned working interests in a total of 475 gross producing wells at year-end. We produced a net of approximately 11 Bcfe of natural gas from the Mid-Continent in 2006. Our estimated proved reserves in the Arkoma and Fort Worth basins at year-end 2006 were 167 Bcfe.

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The following table summarizes our leased acreage as of December 31, 2006:

	Gross Acres	Net Acres
Developed	803,772	423,025
Undeveloped	1,220,422	623,538

At December 31, 2006, we owned working interests in 9,965 gross wells producing hydrocarbons (4,890 net).

Operating statistics

We focus on lower-risk development drilling. Our drilling success rate was 99 percent in 2006, 2005 and 2004. The following tables summarize domestic drilling activity by number and type of well for the periods indicated:

Number of Wells	Gross Wells	Net Wells
Development:		
Drilled		
2006	1,783	954
2005	1,627	867
2004	1,395	710
Successful		
2006	1,770	948
2005	1,615	859
2004	1,384	706

Substantially all our natural gas production is currently being sold to Power at prevailing market prices. Power then resells the majority of our production to unrelated third parties. Because we currently have a low-risk drilling program in proven basins, the main component of risk that we manage is price risk. We have recently 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. Exploration & Production natural gas hedges for 2007 consist of derivative contracts with Power that hedge 172 BBtud in fixed price hedges (whole year) and approximately 270 BBtud in NYMEX and regional collars (whole year) for projected 2007 domestic natural gas production. Power then enters into offsetting derivative contracts with unrelated third parties. Our natural gas production hedges in 2006 consisted of 299 BBtud in fixed price hedges and 64 BBtud in NYMEX collars and an additional 50 BBtud in regional collars. A collar is a financial instrument 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 gas purchase hedging contracts executed on behalf of other Williams entities which taken as a net position may counteract Exploration & Production gas sales hedging derivatives.

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

	2006	2005	2004

Total net production sold (in Bcfe)	274.4	223.5	189.4
Average production costs including production taxes per thousand cubic feet of gas equivalent (Mcfe) produced	$ 1.02	$ .92	$ .88
Average sales price per Mcfe	$ 5.24	$ 6.41	$ 4.48
Realized impact of hedging contracts (Loss)	$ (0.73)	$ (1.61)	$ (1.32)

Acquisitions & divestitures

Exploration & Production expanded its acreage position and purchased producing properties in the Fort Worth basin in north-central Texas through transactions totaling approximately $64 million.

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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, 2007, we own 789,291 trust units. We sold no additional trust units during 2006.

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 4.2 percent of our total proved reserves.

Gas Pipeline

We own and operate, through Williams Gas Pipeline Company, LLC and its subsidiaries, a combined total of approximately 14,400 miles of pipelines with a total annual throughput of approximately 2,500 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 Corporation and Northwest Pipeline Corporation. 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.

Transcontinental Gas Pipe Line Corporation (Transco)

Transco is an interstate natural gas transportation company that owns and operates a 10,500-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, New York, New Jersey, and Pennsylvania.

Pipeline system and customers

At December 31, 2006, 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 3.5 MMdt of natural gas per day for a system-wide delivery capacity total of approximately 8.2 MMdt of natural gas per day. Transco s system includes 44 compressor stations, five underground storage fields, two liquefied natural gas (LNG) storage facilities. Compression facilities at a 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 10 percent of Transco s total revenues in 2006. 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 five underground storage fields located on or near its pipeline system or market areas and operates three 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 216 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, LLC, an LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco s customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Transco expansion projects

Leidy to Long Island Expansion Project

The Leidy to Long Island Expansion Project will involve an expansion of Transco s existing natural gas transmission system in Zone 6 from the Leidy Hub in Pennsylvania to Long Island, New York. The project will provide 100 Mdt/d of incremental firm transportation capacity, which has been fully subscribed by one shipper for a 20-year primary term. The project facilities will include pipeline looping in Pennsylvania, pipeline looping, replacement and a natural gas compressor facility in New Jersey and appurtenant facilities in New York. Transco expects that over three-quarters of the project expenditures will occur in 2007. Transco filed an application for FERC authorization of the project in December 2005, which the FERC approved by order issued on May 18, 2006. On October 20, 2006, Transco filed an application to amend the FERC authorizations to reflect Transco s ownership of certain appurtenant facilities as part of the project and to adjust the cost of facilities and rates, which the FERC approved on January 11, 2007. The estimated capital cost of the project is approximately $141 million. The target in-service date for the project is November 1, 2007.

Potomac Expansion Project

The Potomac Expansion Project will involve an expansion of Transco s existing natural gas transmission system from receipt points in North Carolina to delivery points in the greater Baltimore and Washington, D.C. metropolitan areas. The project will provide 165 Mdt/d of incremental firm transportation capacity, which has been fully subscribed by shippers under long-term firm arrangements. The estimated capital cost of the project is approximately $74 million. On July 17, 2006, Transco filed an application for FERC approval of the project. The target in-service date for the project is November 1, 2007.

Sentinel Expansion Project

The Sentinel Expansion Project will involve an expansion of Transco s 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 project will provide 142 Mdt/d of incremental firm transportation capacity, which has been fully subscribed by the shippers under long-term firm arrangements. The project facilities will include pipeline looping in Pennsylvania and New Jersey and minor compressor station modifications. The estimated capital cost of the project excluding any customer meter station upgrades is approximately $140 million. In order to accommodate certain shippers, Transco is planning to place the incremental firm transportation capacity into service in two phases, the first phase commencing on November 1, 2008 for 67 Mdt/d of service and the second phase commencing on November 1, 2009 for an additional 75 Mdt/d of service. The FERC has granted our request for a pre-application environmental review of the project, soliciting early input from citizens, governmental entities and other interested parties. Transco expects to file a formal application with the FERC in the second quarter of 2007.

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Operating statistics

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

	2006	2005	2004
	(In trillion British Thermal Units)		
Market-area deliveries:			
Long-haul transportation	795	755	782
Market-area transportation	817	853	817
Total market-area deliveries	1,612	1,608	1,599
Production-area transportation	247	278	317
Total system deliveries	1,859	1,886	1,916
Average Daily Transportation Volumes	5.1	5.2	5.2
Average Daily Firm Reserved Capacity	6.6	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 Corporation (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, 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, 2006, Northwest Pipeline s system, having long-term firm transportation agreements with peaking capacity of approximately 3.4 MMdt 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 2003, we experienced two breaks in a segment of one of our natural gas pipelines in western Washington. In response to these breaks, we received Corrective Action Orders from the Office of Pipeline Safety, elected to idle the pipeline segment until its integrity could be assured, and began the process of replacing the capacity served by the pipeline segment.

In September 2005 we received a FERC certificate authorizing us to construct and operate the Capacity Replacement Project. This project entailed the abandonment of approximately 268 miles of the existing 26-inch pipeline, and the construction of approximately 80 miles of new 36-inch pipeline and an additional 10,760 net horsepower of compression at two existing compressor stations. As of December 2006, all of the facilities were placed in service, and abandonment of the 26-inch pipeline was completed.

The rate case we filed on June 30, 2006 seeks to recover, among other things, the capitalized costs relating to the Capacity Replacement Project.

In 2006, Northwest Pipeline served a total of 141 transportation and storage customers. Transportation customers include distribution companies, municipalities, interstate and intrastate pipelines, gas marketers and direct industrial users. The two largest customers of Northwest Pipeline in 2006 accounted for approximately 19.9 percent and 10.9 percent, of its total operating revenues. No other customer accounted for more than 10 percent of Northwest Pipeline s total operating revenues in 2006. Northwest Pipeline s firm transportation agreements are generally long-term agreements 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 600 million cubic feet of gas per day.

Northwest Pipeline expansion projects

Parachute Lateral Project

In January 2006, we filed an application with the FERC to construct a 38-mile lateral that would provide additional transportation capacity from the Parachute area to the Greasewood area in northwest Colorado. The planned lateral would increase capacity by 450 Mdt/d through a 30-inch diameter line and is estimated to cost $86 million. We anticipate beginning service on the expansion in March 2007.

Greasewood Lateral Project

In March 2006, we executed an agreement with a shipper for 200 Mdt/d of capacity on a proposed new lateral to be constructed from the vicinity of Greasewood, Colorado, to our mainline system near Sands Springs, Colorado. On February 20, 2007, following a meeting with representatives of the shipper, we decided to postpone applying with the FERC for a certificate to construct the proposed Greasewood Lateral Project. We will be continuing to work with potential shippers to determine whether to proceed with the project at a future date.

Operating statistics

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

	2006	**2005**	**2004**
	(In trillion British Thermal Units)		
Total Transportation Volume	676	673	650
Average Daily Transportation Volumes	1.9	1.8	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)	.9	.8	.6

(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, because it does not involve the construction of additional mainline capacity.

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. In December 2001, Gulfstream filed an application with the FERC to allow Gulfstream to complete the construction of its approved facilities in phases. In May 2002, the first phase of the project was placed into service at a cost of approximately $1.5 billion. The second phase of the project was placed into service on February 1, 2005. The total capital cost of both phases of the project is approximately $1.7 billion. At December 31, 2006, our equity investment in Gulfstream was $387 million. Gas Pipeline and Spectra Energy (formerly known as Duke Energy), through their respective subsidiaries, each hold a 50 percent ownership interest in Gulfstream and provide operating services for Gulfstream.

Gulfstream expansion projects

Gulfstream has entered into a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, we intend to extend the pipeline system into South Florida and fully subscribe 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 anticipated to be approximately $135 million. Gulfstream also has executed a precedent agreement and a related firm transportation service agreement pursuant to which, subject to the receipt of all necessary regulatory approvals and other conditions precedent therein, we intend to construct and fully subscribe on a long-term basis the first incremental expansion of Gulfstream s mainline capacity, increasing the current mainline capacity of 1.1 MMdt/d to 1.255 MMdt/d. The project will include the construction of additional pipeline in Florida and the installation of new compression in Alabama and Florida. The estimated capital cost of this expansion is anticipated to be approximately $117 million. No significant increase in operations personnel is expected as a result of these two projects.

Midstream Gas & Liquids

Our Midstream segment, one of the nation s largest natural gas gatherers and processors, has primary service areas concentrated in the 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; natural gas liquids (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 plastics, home heating and refinery feedstock.

Although most of our gas services are performed for a volumetric-based fee, a portion of our gas processing contracts are commodity-based and include two distinct types of commodity exposure. The first type includes Keep Whole processing contracts whereby we own the NGLs extracted and replace the lost heating value with natural gas. Under these contracts, we are exposed to the spread between NGLs and natural gas prices. The second type consists of Percent of Liquids contracts whereby we receive a portion of the extracted liquids with no direct exposure to the price of natural gas. Under these contracts, we are only exposed to NGL price movements.

Our Canadian and Gulf Liquids olefin facilities have commodity exposure. In Canada, we are exposed to the spread between the price for natural gas and the olefinic products we produce. In the Gulf Coast, 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. In the Gulf Coast, we also 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.

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;
- prices impacting our commodity-based processing and olefin activities.

Domestic gathering and processing

We own and/or operate domestic gas gathering and processing assets primarily within the western states of Wyoming, Colorado and New Mexico, and the onshore and offshore shelf and deepwater areas in and around the Gulf Coast states of Texas, Louisiana, Mississippi and Alabama. These assets consist of approximately 8,200 miles of gathering pipelines, nine processing plants (one partially owned) and five natural gas treating plants with a combined daily inlet capacity of nearly 6.2 billion cubic feet per day. Some of these assets are owned through our interest in Williams Partners L.P. (see Williams Partners L.P. section below).

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 85 percent of our Exploration & Production group s wellhead production in this basin. Both our San Juan Basin and Southwest Wyoming systems deliver gas volumes into Northwest Pipeline s interstate system.

In addition to these natural gas assets, we own and operate three crude oil pipelines totaling approximately 270 miles with a capacity of more than 300,000 barrels per day. This includes our Mountaineer, Alpine and BANJO crude oil pipeline systems in the deepwater Gulf of Mexico.

The BANJO oil pipeline and Seahawk gas pipeline run parallel and deliver production across two producer-owned spar-type floating production systems from the Kerr-McGee-operated Boomvang and Nansen field areas in the western Gulf of Mexico. These pipelines were placed in service on January 28, 2002.

Our 18 inch oil pipeline, Alpine, which became operational on December 14, 2003, is our second western gulf crude oil pipeline. The pipeline extends 96 miles from Garden Banks Block 668 in the central Gulf of Mexico to our shallow-water platform at Galveston Area Block A244. From this platform, the oil is delivered onshore through ExxonMobil s Hoover Offshore Oil Pipeline System under a joint tariff agreement. This production is coming from the Gunnison field, which is located in 3,150 feet of water and operated by Kerr-McGee.

Our Devils Tower floating production system and associated pipelines were placed in service on May 5, 2004. Initially built to serve Dominion Exploration & Production s Devils Tower field, the floating production system is located in Mississippi Canyon Block 773, approximately 150 miles south-southwest of Mobile, Alabama. During the fourth quarter of 2005, the platform s service expanded to include tie-backs of production from the Triton and Goldfinger fields in addition to the host Devils Tower field. Located in 5,610 feet of water, it is the world s deepest dry tree spar. The platform, which is operated by Dominion on our behalf, is capable of producing 60 MMcf/d of natural gas and 60 Mbbls/d of oil.

The Devils Tower project includes gas and oil pipelines. The 102-mile Canyon Chief gas pipeline consists of 18-inch diameter pipe. The 118-mile Mountaineer oil pipeline is a combination of 18- and 20-inch diameter pipe. The gas is delivered into Transco s pipeline, and processed at our Mobile Bay plant to recover the NGLs. The oil is transported to ChevronTexaco s Empire Terminal in Plaquemines Parish, Louisiana. These associated pipelines are significantly oversized relative to the Devils Tower spar top-side capacity.

Included in the natural gas assets listed above are the assets of Discovery Producer Services LLC and its subsidiary Discovery Gas Transmission Services LLC (Discovery). We own a partial interest in Discovery and operate its facilities. Discovery s assets include a cryogenic natural gas processing plant near Larose, Louisiana, a natural gas liquids fractionator plant near Paradis, Louisiana and an offshore natural gas gathering and transportation system.

Gulf Coast petrochemical and olefins

We own a 5/12 interest in and are the operator for an ethane cracker at Geismar, Louisiana, with a total production capacity of 1.3 billion pounds per year of ethylene. We also own an ethane pipeline system in Louisiana. Our Gulf Liquids New River LLC (Gulf Liquids) business consists of a propylene splitter and its related pipeline system.

Canada

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 from third party oil sands bitumen upgrading and then fractionate, treat, store, terminal and sell the propane, propylene, butane and condensate recovered from this process. 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 valuable petrochemical feedstocks from upgrader off-gas streams allowing the upgraders to burn cleaner natural gas streams

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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 NGL products.

Venezuela

Our Venezuelan investments involve gas compression and gas processing and natural gas liquids fractionation operations. We own controlling interests and operate three gas compressor facilities which provide roughly 70 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. We also own a 49.25 percent interest in two 400 MMcf/d natural gas liquids extraction plants, a 50,000 barrels per day natural gas liquids fractionation plant and associated storage and refrigeration facilities.

Other

We own interests in and/or operate NGL fractionation and storage assets. These assets include two partially owned NGL fractionation facilities near Conway, Kansas and Baton Rouge, Louisiana that have a combined capacity in excess of 167,000 barrels per day. We also own approximately 20 million barrels of NGL storage capacity in central Kansas. Some of these assets are owned through our interest in Williams Partners L.P.

Williams Partners L.P.

Williams Partners L.P. (Williams Partners) was formed to engage in the business of gathering, transporting and processing natural gas and fractionating and storing NGLs. We own approximately 22.5 percent of Williams Partners. Williams Partners provides us with an acquisition currency that is expected to enable growth of our Midstream business. Williams Partners also creates a vehicle to monetize our qualifying assets. Such transactions, which are subject to approval by both our and Williams Partners general partner s board of directors, allow us to retain control of the assets through our ownership interest in Williams Partners.

During 2006, Williams Partners L.P. acquired Williams Four Corners, LLC which includes a 3,500-mile natural gas gathering system in the San Juan Basin in New Mexico and Colorado with capacity of nearly 2 billion cubic feet per day; the Ignacio natural gas processing plant in Colorado and the Kutz and Lybrook natural gas processing plants in New Mexico, which have a combined processing capacity of 760 million cubic feet per day; and the Milagro and Esperanza natural gas treating plants in New Mexico, which are designed to remove carbon dioxide from up to 750 million cubic feet of natural gas per day.

In addition, Williams Partners owns a 40 percent equity investment in the Discovery gathering, transportation, processing and NGL fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50 percent interest in an NGL fractionator near Conway, Kansas.

Expansion projects

Gathering and processing

In May 2006, we entered into an agreement to develop new pipeline capacity for transporting natural gas liquids from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we incurred to date for the proposed pipeline and initially will own 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for early 2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered.

We are constructing a fifth cryogenic processing train at our existing gas plant in Opal, Wyoming, which is scheduled for start-up in the first quarter of 2007. The expansion is designed to boost the plant s processing capacity by more than 30 percent to 1.45 billion cubic feet per day. Opal also will be able to recover a total of approximately 67,000 barrels per day of natural gas liquids.

Gathering and processing deepwater projects

The deepwater Gulf continues to be an attractive growth area for our Midstream business. Since 1997, we have invested almost $1 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.

Chevron and Kerr-McGee are dedicating to us the transport of production from their current and future ownership in a defined area surrounding the Blind Faith discovery in the deepwater Gulf of Mexico. To accommodate production from the Blind Faith acreage and the surrounding blocks, we have agreed to extend our Canyon Chief and Mountaineer pipelines to the producer-owned floating production facility. We expect to have the extensions ready for service in second quarter 2008. The approximately $200 million project will facilitate a 37-mile extension of each pipeline. The agreement also creates opportunities for us to move natural gas from the Blind Faith discovery through our Mobile Bay, Alabama, processing plant and our Transco and Gulfstream interstate pipeline systems. Recovered natural gas liquids from Blind Faith also could be fractionated at our facilities in Baton Rouge or Paradis, Louisana.

Customers and operations

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 2006, these operations gathered and processed gas for approximately 220 gas gathering and processing customers. Our top three gathering and processing customers accounted for about 44 percent of our domestic gathering and processing revenue. Our gathering and processing agreements are generally long-term agreements.

In addition to our gathering and processing operations, we market NGLs and petrochemical products to a wide range of users in the energy and petrochemical industries. We provide these products to third parties from the production at our domestic facilities. The majority of domestic sales are based on supply contracts of less than one year in duration. The production from our Canadian facilities is marketed in Canada and in the United States.

Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petróleos de Venezuela S.A. The significant contracts have a remaining term between 11 and 15 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 has continued its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and continues to publicly declare that additional energy contracts will be unilaterally amended and privately held assets will be expropriated, indicating that a level of political risk still remains.

Operating statistics

The following table summarizes our significant operating statistics for Midstream:

	2006	**2005**	**2004**
Volumes(1):			
Domestic Gathering (trillion British Thermal Units)	1,181	1,253	1,252
Domestic Natural Gas Liquid Production (Mbbls/d)(2)	152	144	155
Crude Oil Gathering (Mbbls/d)(2)	86	88	83

Processing Volumes (trillion British Termal Units)	833	721	768

(1) Excludes volumes associated with partially owned assets that are not consolidated for financial reporting purposes.

(2) Annual Average Mbbls/d

Power

Our Power business buys, sells, stores and transports energy and energy-related commodities, primarily power and natural gas. Power s focus is not only on its objective of maximizing expected cash flows, but also on executing new contracts to hedge its portfolio and providing services that support our natural gas businesses across Williams. Our contracts include physical forward purchases and sales, various financial instruments and structured transactions. Our financial instruments include exchange-traded futures, as well as exchange-traded and over-the-counter options and swaps. Structured transactions include tolling contracts, full requirements contracts, tolling resales and heat rate options.

Tolling contracts represent the most significant portion of our portfolio. Under the tolling contracts, we have the right to request a plant owner to convert our fuel (usually natural gas) to electricity in exchange for a fixed fee. We have the right to request approximately 7,700 megawatts of electricity under six tolling agreements. The table below lists the locations and available capacity of each of our tolling agreements. These capacity numbers are subject to change, and our contractual rights to capacity may not reflect actual availability at the plants.

Location	**Megawatts**
California	4,141
Alabama	844
Louisiana	758
New Jersey	766
Pennsylvania	664
Michigan	545
Total	**7,718**

We use portions of the electricity produced under the tolling agreements to supply obligations under various arrangements such as power sales, tolling resales, and full requirements contracts. Under full requirements contracts, we supply the electricity required by our counterparties to serve their customers. Through full requirements contracts, we supply approximately 600 to 1,500 megawatts of electricity to our customers in Georgia and approximately 515 to 600 megawatts of electricity to our customers in Pennsylvania. The amount of electricity we supply under these contracts varies year to year but is expected to grow annually. Each year, the amount of electricity we supply is subject to a growth cap.

Through tolling resale agreements, we enter into transactions that mirror, to varying degrees, some or all of our rights under our underlying tolling arrangements, which remain in place with our tolling counterparties. We have resold part of our rights (1,934 to 3,875 megawatts) under the California tolling arrangement to two counterparties for periods through 2011. These volumes include amounts sold under contracts executed in 2007.

We also own two natural gas-fired electric generating plants located near Bloomfield, New Mexico (60 megawatts, Milagro facility) and in Hazleton, Pennsylvania (147 megawatts).

In 2006, we managed natural gas throughout North America with total physical volumes averaging 2.3 billion cubic feet per day. We use approximately 10 percent of this natural gas to fuel electric generating plants we own or in which we have contractual rights. We sell approximately 70 percent of this natural gas to customers including local distribution companies, utilities, producers, industrials and other gas marketers. With the remaining 20 percent, we procure gas supply for our Midstream operations.

In 2004, we substantially exited our crude oil and refined products activities.

Operating statistics

The following table summarizes marketing and trading gross sales volumes, including sales volumes to other segments, for the periods indicated:

	Year Ending December 31,		
	2006	2005	2004
Marketing and trading physical volumes:			
Power (thousand megawatt hours)	53,866	66,779	93,998
Natural gas (billion cubic feet per day)	2.1	2.1	2.3
Petroleum products (thousand barrels per day)			50

In 2006, Power managed 2.3 billion cubic feet per day of natural gas. The natural gas volumes managed include the following (in billion cubic feet per day):

	2006
Sales to third parties	1.7
Sales to other segments	.4
For use in tolling agreements and by owned generation	.2
Total natural gas managed	2.3

As of December 31, 2006, Power had approximately 350 customers compared with approximately 300 customers at the end of 2005.

Other

At December 31, 2004, we owned approximately 94.7 percent of the Class B Interests and 21.3 percent of the Common Interests in Longhorn Partners Pipeline LP (Longhorn), which owned a refined petroleum products pipeline from Houston, Texas to El Paso, Texas. The Class B Interests are preferred interests but subordinate to other preferred interests, and the Common Interests are subordinate to both.

During the first quarter of 2005, Longhorn became fully operational as deliveries commenced through both the Odessa and El Paso terminals. However, the pipeline s throughput fell significantly short of management expectations. The primary driver behind this volume shortfall was the narrowing of the refined product pricing differentials between the Gulf Coast and El Paso markets. During the second quarter of 2005, Longhorn management indicated the shortfall was likely to continue and that the original business model was no longer feasible.

As a result of the other-than-temporary decline in fair value identified in the second quarter of 2005, we impaired the Common Interests by $16.2 million and the Class B shares by $32.7 million. After these adjustments, the book value of our investment in Longhorn (as of June 30, 2005) totaled $51.6 million, comprised of $25.0 million of Common Interests and $26.6 million of Class B shares.

During the third quarter of 2005, we provided $10 million of a $50 million fully collateralized bridge loan to fund operations of Longhorn until an economically feasible operational alternative was developed. In the fourth quarter of 2005, management of Longhorn concluded that its best alternative would be to sell the Longhorn assets. Accordingly, they directed a financial advisor to solicit offers from several entities. After reviewing the terms and conditions of bids received, our management determined that a full impairment of our investment in the Class B and Common Interests was appropriate. This decision resulted in a December 31, 2005 write-down of the remaining $38.1 million in book value which had been further reduced by additional equity losses during the third and fourth quarters.

The management of Longhorn completed an installment sale of the pipeline during the third quarter of 2006, and as a result we received full payment of the $10 million secured bridge loan that we provided to Longhorn during 2005. It is uncertain whether we will ever receive any payments related to our Class B Interests or our Common

Interests, however any such amounts related to these fully impaired interests will only be recognized as income when received.

We continue to receive payments associated with the 2005 transfer of the First Amended and Restated Pipeline Operating Services Agreement to a third party. The sale of the pipeline did not impact these ongoing payments which are recognized as income when received.

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 sold in 2003 and 2004 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.

Our corporate parent company performs certain management, legal, financial, tax, consultative, administrative and other services for our subsidiaries.

Our corporate parent company s principal sources of cash are from external financings, dividends and advances from our subsidiaries, investments, payments by subsidiaries for services rendered, interest payments from subsidiaries on cash advances 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 our corporate parent.

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 Power, 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, 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, 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 their marketing affiliates. Among other things, the Standards of Conduct require that interstate pipelines not operate their systems to preferentially benefit their marketing affiliates.

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

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes;
- volume throughput assumptions.

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

Midstream. 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 gathering facilities located offshore are not subject to the NGA (although offshore transmission pipelines may be), some controversy exists as to how the FERC should determine whether offshore facilities function as gathering. These issues are currently before the FERC. 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 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 Gas Transmission LLC 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 Commission before any changes can go into effect. Currently, Black Marlin has a major rate change application pending before the Commission to increase its rates for service.

Our remaining Midstream Canadian assets are regulated by the Alberta Energy & Utilities Board (AEUB) 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 AEUB and Alberta Environment have implemented an enforcement process with escalating consequences.

Power. Our Power business is subject to a variety of laws and regulations at the local, state and federal levels, including FERC and the Commodity Futures Trading Commission regulation. In addition, electricity and natural gas markets in California and elsewhere 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 15 of our Notes to Consolidated Financial Statements for further details on our regulatory matters.

ENVIRONMENTAL MATTERS

Our generation 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, transportation facilities and storage tanks;
- damage to oil and gas wells resulting from accidents during normal operations;
- blowouts, cratering and explosions.

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

We believe compliance with environmental laws and regulations will not have a material adverse effect on capital expenditures, earnings or competitive position. However, environmental laws and regulations could affect our business in various ways from time to time, including incurring capital and maintenance expenditures, imposing limitations on generation facility availability, 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 (which we believe would be granted).

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 15 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. Our Gas Pipeline segment faces increased competition as a result of various actions taken by the FERC and several states in which we operate to strengthen market forces in the natural gas pipeline industry. In a number of key markets, interstate pipelines are now facing competitive pressures from other major pipeline systems, enabling local distribution companies and end users to choose a supplier or switch suppliers based on the short-term price of gas and the cost of transportation. We expect competition for natural gas transportation to continue to intensify in future years due to increased customer access to other pipelines, rates, competitiveness among pipelines, customers desire to have more than one transporter, shorter contract terms, regulatory developments, and development of LNG facilities particularly in our market areas. Future utilization of pipeline capacity will depend on competition from other pipelines and LNG facilities, use of alternative fuels, the general level of natural gas demand, and weather conditions.

Suppliers of natural gas are able to compete for any gas markets capable of being served by pipelines using nondiscriminatory transportation services provided by the pipeline companies. As the regulated environment has matured, many pipeline companies have faced reduced levels of subscribed capacity as contractual terms expire and customers opt to reduce firm capacity under contract in favor of alternative sources of transmission and related services. This situation, known in the industry as capacity turnback, is forcing the pipeline companies to evaluate the consequences of major demand reductions in traditional long-term contracts. It could also result in significant shifts in system utilization, and possible realignment of cost structure for remaining customers because all interstate natural gas pipeline companies continue to be authorized to charge maximum rates approved by the FERC on a cost of service basis. Gas Pipeline does not anticipate any significant financial impact from capacity turnback. We anticipate that we will be able to remarket most future capacity subject to future capacity turnback, although competition may cause some of the remarketed capacity to be sold at lower rates or for shorter terms.

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Midstream. 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, master limited partnerships (MLP), 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 well connections, pressure obligations and contract structure. We also compete in recruiting and retaining skilled employees. In 2005 we formed Williams Partners to help compete against other master limited partnerships for midstream projects. By virtue of the master limited partnership structure, Williams Partners provides us with an alternative and low-cost source of capital. We expect the alternative, low-cost capital will allow Williams Partners to compete with other MLPs when pursuing acquisition opportunities of gathering and processing assets.

Power. In our Power 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, 2007, we had approximately 4,313 full-time employees including 972 at the corporate level, 584 at Exploration & Production, 1,694 at Gas Pipeline, 928 at Midstream, and 135 at Power. None of our employees are represented by unions or covered by collective bargaining agreements.

FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Note 17 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 17 of our Notes to Consolidated Financial Statements for information relating to long-lived assets during the last three fiscal years, other than financial instruments, long-term customer relationships of a financial institution, mortgage and other servicing rights and deferred policy acquisition costs, 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 those 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 which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements include, among others, statements regarding:

- amounts and nature of future capital expenditures;

expansion and growth of our business and operations;

business strategy;

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- estimates of proved gas and oil reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations;
- seasonality of certain business segments;
- power, natural gas and natural gas liquids prices and demand.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. 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 and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;
- inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;
- 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;
- changes in the current geopolitical situation;
- risks related to strategy and financing, including restrictions stemming from our debt agreements and our lack of investment grade credit ratings;
- risk associated with future weather conditions and acts of terrorism.

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 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 additions to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. These factors include the following:

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.

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Risks Inherent to our Industry and Business

The long-term financial condition of our natural gas transmission 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 market demand for natural gas.

The development of the additional natural gas reserves that are essential for our gas transmission 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 transmission and import and export of natural gas supplies, adversely impacting our ability to fill the capacities of our gathering, transmission and processing facilities. Additionally, in some cases, new LNG import facilities built near our markets could result in less demand for our gathering and transmission facilities.

Estimating reserves and future net revenues involves uncertainties. Negative revisions to reserve estimates and oil and gas price declines may lead to decreased earnings, losses or impairment of oil and gas assets.

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 over time.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Lower oil and gas prices 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. The revisions may also be sufficient to trigger impairment losses on certain properties which would result in a further non-cash charge to earnings. The revisions could also possibly affect the evaluation of Exploration & Production s goodwill for impairment purposes.

Our past success rate for drilling projects and the historic performance of our exploration and production business is no predictor of future performance.

Our past success rate for drilling projects in 2006 should not be considered a predictor of future performance.

Performance of our exploration and production business is affected in part by factors beyond our control (any of which could cause the results of this business to decrease materially), such as:

- regulations and regulatory approvals;
- availability of capital for drilling projects which may be affected by other risk factors discussed in this report;
- cost-effective availability of drilling rigs and necessary equipment;

availability of skilled labor;

availability of cost-effective transportation for products;

market risks (including price risks and competition) discussed in this report.

Our drilling, production, gathering, processing 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:

blowouts, cratering and explosions;

uncontrollable flows of oil, natural gas or well fluids;

fires;

formations with abnormal pressures;

pollution and other environmental risks;

natural disasters.

In addition, there are inherent in our gas gathering, processing and transporting properties a variety of hazards and operating risks, such as leaks, spills, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in loss of human life, 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 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 could materially impact our ability to meet contractual obligations and retain customers, with a resulting impact on our results of operations.

Costs of environmental liabilities and complying with existing and future environmental regulations 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.

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.

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

Revenues from certain segments of our business, including gas transmission and the sale of electric power, can have seasonal characteristics. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, demand for power peaks during the winter. In addition, 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 power sale agreements and natural gas transmission 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 Power, which uses gas as a fuel source, may not.

Risks Related to the Current Geopolitical Situation

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 proposed 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. Foreign currency risk can also arise when the revenues received by our foreign subsidiaries are not in U.S. dollars. In such cases, a strengthening of the U.S. dollar or a weakening of the foreign currency could reduce the amount of cash and income we receive from these foreign subsidiaries. We have put contracts in place designed to mitigate our most significant 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.

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, sell assets, make certain distributions, repurchase equity 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 lack of investment grade credit ratings increases our costs of doing business in certain ways and attainment of an investment grade rating is within the control of independent third parties.

Because we do not have an investment grade credit rating, our transactions in each of our businesses require greater credit assurances, both to be given from, and received by, us to satisfy credit support requirements. In addition, we are more vulnerable to the impact of market disruptions or a further downgrade of our credit rating that might further increase our cost of borrowing or further impair our ability to access capital markets. Such disruptions could include:

- economic downturns;
- deteriorating capital market conditions generally;
- declining market prices for electricity and natural gas;
- terrorist attacks or threatened attacks on our facilities or those of other energy companies;
- the overall health of the energy industry, including the bankruptcy or insolvency of other companies.

Credit rating agencies perform independent analysis when assigning credit ratings. Given the significant changes in capital markets and the energy industry over the last few years, credit rating agencies continue to review the criteria for attaining investment grade ratings and make changes to those criteria from time to time. Our goal is to attain investment grade ratios. However, there is no guarantee that the credit rating agencies will assign us investment grade ratings even if we meet or exceed their criteria for investment grade ratios.

Long-term power generation purchase contracts without corresponding long-term purchase sale contracts might expose us to fluctuations in the wholesale power markets and negatively affect our results of operations.

We have entered into agreements with certain power generation facilities to purchase all or a substantial portion of their generation capacity. These facilities operate as merchant facilities, many without corresponding long-term power sales agreements, and therefore are exposed to market fluctuations. Without the benefit of such

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long-term power sales agreements, we cannot be sure that we will be able to sell any or all of the power generated by these facilities at commercially attractive rates or that these power generation relationships will be profitable.

We sell all or a portion of the energy, capacity and other products from certain generation facilities to wholesale power markets, including energy markets operated by independent system operators, or ISOs, or regional transmission organizations, or RTOs, as well as wholesale purchasers. We are not subject to traditional cost-based regulation, therefore we sell electric generation capacity, power and ancillary services to wholesale purchasers at prices determined by the market. As a result, we are not guaranteed any rate of return on our capital investments through mandated rates, and our revenues and results of operations depend upon current and forward market prices for power.

Prices for electricity, 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 our power and gas businesses depend primarily upon the prices we receive for electricity, natural gas liquids, natural gas, or other commodities, and the differences between prices of these commodities. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. In particular, market prices for power, generation capacity and ancillary services tend to fluctuate substantially. Unlike other commodities, electricity can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, market prices for electricity are subject to significant volatility from supply and demand imbalances, especially in the day-ahead and spot markets.

The markets for electricity, natural gas liquids, and natural gas 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 electricity, natural gas, petroleum, and related commodities;
- turmoil in the Middle East and other producing regions;
- terrorist attacks on production or transportation assets;
- weather conditions;
- the level of consumer demand;
- the development of federal and state power markets, including actions of ISOs and RTOs;
- the price and availability of other types of fuels;
- the availability of pipeline capacity;
- supply disruptions, including plant outages and transmission 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.

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 consists of wholesale contracts to buy and sell commodities, including contracts for electricity, natural gas, natural gas liquids 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 financing transaction fails to perform and any collateral that secures our counterparty s obligation is inadequate, we will suffer a loss.

If we are unable to perform under our energy agreements, we could be required to pay damages. These damages generally would be based on the difference between the market price to acquire replacement energy or energy services and the relevant contract price. Depending on price volatility in the wholesale energy markets, such damages could be significant.

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, transmission, and storage operations conducted through our Gas Pipelines business are subject to the FERC s rules and regulations in accordance with the Natural Gas Act of 1938 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 and charges;
- construction;
- acquisition, extension or abandonment of services or facilities;
- accounts and records;
- depreciation and amortization policies;
- operating terms and conditions of service.

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.

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 transmission provider based on considerations other than location.

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.

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Expiration of firm transportation agreements.

A substantial portion of the operating revenues of our Gas Pipelines are generated through firm transportation agreements that expire periodically and must be renegotiated and extended or replaced. We cannot give any assurance as to whether any of these agreements will be extended or replaced or that the terms of any renegotiated agreements will be as favorable as the existing agreements. Upon the expiration of these agreements, should customers turn back or substantially reduce their commitments, we could experience a negative effect to our results of operations.

Our revenues might decrease if we are unable to gain adequate, reliable and affordable access to transmission and distribution assets due to regulation by the FERC and regional authorities of wholesale market transactions for electricity and natural gas.

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas we buy and sell in the wholesale market. If transmission is disrupted, if capacity is inadequate, or if credit requirements or rates of such utilities or energy companies are increased, our ability to sell and deliver products might be hindered. The FERC has issued power transmission regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, some companies may fail to provide fair and equal access to their transmission systems or may not provide sufficient transmission capacity to enable other companies to transmit electric power.

In addition, the independent system operators who oversee the transmission systems in regional power markets, such as California, have in the past been authorized to impose, and might continue to impose, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms might adversely impact the profitability of our wholesale power marketing and trading. Given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by regulators, ISOs, RTOs or other marker operators, we can offer no assurance that we will be able to operate profitably in all wholesale power markets or that our results of operations will not be adversely affected by the actions of these parties.

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.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us or our facilities, and future changes in laws and regulations might have a detrimental effect on our business. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

The outcome of pending rate cases to set the rates we can charge customers on certain of our pipelines might result in rates that do not provide an adequate return on the capital we have invested in those pipelines.

We have filed rate cases with the FERC to request changes to the rates we charge on Northwest Pipeline and Transco. Although we have a pending settlement of our Northwest Pipeline rate case, we must still obtain approval of the settlement. Therefore, the outcome of both rate cases remains uncertain. There is a risk that rates set by the FERC will be lower than is necessary to provide us with an adequate return on the capital we have invested in these assets. There is also the risk that higher rates will cause our customers to look for alternative ways to transport their natural gas.

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 Accounting Standards

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.

Accounting irregularities discovered in the past few years across various industries have forced regulators and legislators 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.

Risks Related to Market Volatility and Risk Measurement and Hedging Activities

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

We manage our commodity price risk for our unregulated businesses as a whole. Although we have systems in place that use various methodologies to quantify risk, 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, including our long-term tolling agreements. 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, as well as long-term structured transactions when feasible. 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 tolling 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 and could also result in reported cash flows in future years not reflecting the realization of increases in the fair value of derivatives that have already been reflected in our income statements. 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 as hedges under 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. During the period from 2002 to 2004 when our Power business was for sale, most changes in the fair value of derivatives used in our Power business were reflected in our earnings as net forward unrealized mark-to-market gains. As a result, in future periods if the cash benefits associated with those hedges are actually realized, the value will not be reflected as earnings on our income statement, having already been recorded as earnings in prior years.

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;
- a change in the difference between published price indexes established by pipelines in which our hedged production is delivered and the reference price established in the hedging arrangements is such that we are required to make payments to our counterparties;
- the counterparties to our hedging arrangements fail to honor their financial commitments.

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 the 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.

Our ability to receive services from outsourcing provider locations outside of the United States might be impacted by cultural differences, political instability, or unanticipated regulatory requirements in jurisdictions outside the United States.

Certain of our accounting, information technology, application development, and helpdesk 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.

Our current information technology infrastructure is aging and may adversely affect our ability to conduct our business.

Limited capital spending for information technology infrastructure during 2001-2003 resulted in an aging server environment that may be less efficient, may require more personnel and capital resources to maintain and upgrade than more current systems, and may not be adequate for our current business needs. While efforts are ongoing to update the environment, the current age and condition of equipment could result in loss of internal and external communications, loss of data, inability to access data when needed, excessive software downtime (including downtime for critical software applications), and other disruptions that could have a material adverse impact on our business and results of operations.

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, 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.

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 generate, produce, process, transmit, transport or distribute electricity, natural gas or natural gas liquids. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

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

Power s primary assets are its term contracts, related systems and technological support. In addition, affiliates of Power own the Hazelton and Milagro generating facilities described above. 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 15 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 22, 2007, are listed below.

Alan S. Armstrong	Senior Vice President, Midstream Age: 44 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.
James J. Bender	Senior Vice President and General Counsel Age 50 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. since June 1997. NRG Energy, Inc. filed a voluntary bankruptcy petition during 2003 and its plan of reorganization was approved in December 2003.
Donald R. Chappel	Senior Vice President and Chief Financial Officer Age: 55 Position held since April 2003. Prior to joining us, Mr. Chappel during 2000 founded and served as chief executive officer of a development business in Chicago, Illinois through April 2003, when he joined us. Mr. Chappel joined Waste Management, Inc. in 1987 and held various financial, administrative and operational leadership positions, including twice serving as chief financial officer, during 1997 and 1998 and most recently during 1999 through February 2000.
Ralph A. Hill	Senior Vice President, Exploration & Production Age: 47 Position held since December 1998.

Mr. Hill was vice president of the exploration and production unit from 1993 to 1998 as well as Senior Vice President Petroleum Services from 1998 to 2003.

William E. Hobbs	Senior Vice President, Power Age: 47 Position held since October 2002. From February 2000 to October 2002, Mr. Hobbs was President and Chief Executive Officer of Williams Energy Marketing & Trading. From 1997 to February 2000, he served as a Vice President of various Williams subsidiaries.

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Michael P. Johnson, Sr.	Senior Vice President and Chief Administrative Officer Age: 59 Position held since May 2004. Mr. Johnson was named our Senior Vice President of Human Resources and Administration in April 1999. Prior to joining us in December 1998, he held officer level positions, such as Vice President of Human Resources, Vice President for Corporate People Strategies, and Vice President Human Resource Services, for Amoco Corporation from 1991 to 1998.
Steven J. Malcolm	Chairman of the Board, Chief Executive Officer and President Age: 58 Position held since September 2001. Mr. Malcolm was elected Chief Executive Officer of Williams in January 2002 and Chairman of the Board in May 2002. He was elected President and Chief Operating Officer in September 2001. Prior to that, he was our Executive Vice President from May 2001, President and Chief Executive Officer of our subsidiary Williams Energy Services, LLC, since December 1998 and the Senior Vice President and General Manager of our subsidiary, Williams Field Services Company, since November 1994.
Phillip D. Wright	Senior Vice President, Gas Pipeline Age: 51 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.

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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 and NYSE Arca Equities Exchanges under the symbol WMB. At the close of business on February 22, 2007, we had approximately 11,875 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:

	2006			2005		
Quarter	**High**	**Low**	**Dividend**	**High**	**Low**	**Dividend**
1st	$ 25.12	$ 19.49	$ .075	$ 19.29	$ 15.29	$ .05
2nd	$ 23.36	$ 20.33	$ .09	$ 19.21	$ 16.29	$ .05
3rd	$ 25.23	$ 22.51	$ .09	$ 25.05	$ 19.16	$ .075
4th	$ 27.95	$ 22.95	$ .09	$ 25.40	$ 19.97	$ .075

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. However, until January 20, 2005, the credit agreements underlying our two unsecured revolving credit facilities totaling $500 million prohibited us from paying quarterly cash dividends on our common stock in excess of $0.05 per share. On January 20, 2005, these facilities were terminated and replaced with two new facilities. As part of the transaction, the dividend restriction, along with most of the other restrictive covenants, was removed from the new credit agreements.

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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, 2002. The Bloomberg U.S. Pipeline Index is composed of El Paso, Equitable Resources, Questar, Kinder Morgan, TransCanada, Spectra Energy, Enbridge and Williams. The graph below assumes an investment of $100 at the beginning of the period.

Cumulative Total Shareholder Return

	2001	2002	2003	2004	2005	2006
The Williams Companies, Inc.	100.0	11.1	40.6	67.7	97.5	111.5
S&P 500 Index	100.0	77.9	100.2	111.1	116.6	135.0
Bloomberg U.S. Pipelines Index	100.0	30.7	50.4	64.1	82.8	93.7

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

The following financial data as of December 31, 2006 and 2005, and for the three years ended December 31, 2006, are an integral part of, and should be read in conjunction with, the consolidated financial statements and related notes. All other amounts have been prepared from our financial records. Certain amounts below have been restated or reclassified. See Note 1 of Notes to Consolidated Financial Statements in Part II Item 8 for discussion of changes in 2006, 2005 and 2004. Information concerning significant trends in the financial condition and results of operations is contained in *Management s Discussion & Analysis of Financial Condition and Results of Operations* of this report.

	2006	2005	2004	2003	2002
			(Millions, except per-share amounts)		
Revenues(1)	$ 11,812.9	$ 12,583.6	$ 12,461.3	$ 16,651.0	$ 3,434.5
Income (loss) from continuing operations(2)	332.8	317.4	93.2	(57.5)	(618.4)
Income (loss) from discontinued operations(3)	(24.3)	(2.1)	70.5	326.6	(136.3)
Cumulative effect of change in accounting principles(4)		(1.7)		(761.3)	
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	.55	.53	.18	(.17)	(1.37)
Income (loss) from discontinued operations	(.04)		.13	.63	(.26)
Cumulative effect of change in accounting principles				(1.47)	
Total assets at December 31	25,402.4	29,442.6	23,993.0	27,021.8	34,988.5
Short-term notes payable and long-term debt due within one year at December 31	392.1	122.6	250.1	938.5	2,077.1
Long-term debt at December 31	7,622.0	7,590.5	7,711.9	11,039.8	11,075.7
Stockholders equity at December 31	6,073.2	5,427.5	4,955.9	4,102.1	5,049.0
Cash dividends per common share	.345	.25	.08	.04	.42

(1) As part of our adoption of Emerging Issues Task Force Issue No. 02-3 Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, (EITF 02-3), we concluded that revenues and costs of sales from nonderivative contracts and certain physically settled derivative contracts should generally be reported on a gross basis. Prior to the adoption on January 1, 2003, these revenues were presented net of costs. As permitted by EITF 02-3, prior year amounts have not been restated. Additionally, *revenues* within our Power segment in 2003 includes approximately $117 million related to the correction of the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001.

(2) See Note 4 of Notes to Consolidated Financial Statements for discussion of asset sales and other accruals in 2006, 2005, and 2004.

(3) See Note 2 of Notes to Consolidated Financial Statements for the analysis of the 2006, 2005 and 2004 income (loss) from discontinued operations. Results for the years 2003 and 2002 also include amounts related to the discontinued operations of certain gas processing and natural gas liquid operations in Canada, a soda ash mining operation, our interest and investment in Williams Energy Partners, a bio-energy operation, certain natural gas production properties, Texas Gas Transmission Corporation, refining and marketing operations in the midsouth, retail travel centers in the midsouth, Central natural gas pipeline, Mid-America pipeline, Seminole pipeline and Kern River pipeline.

(4) The 2005 *cumulative effect of change in accounting principles* is due to implementation of Interpretation (FIN) 47, Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143. The 2003 cumulative effect of change in accounting principles includes a $762.5 million charge related to the adoption of EITF 02-3, slightly offset by $1.2 million related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations. The $762.5 million charge primarily consisted of the then fair value of power tolling, load serving, gas transportation and gas storage contracts. These contracts are not derivatives and, therefore, are no longer reported at fair value.

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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. We also manage a wholesale power business. 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 Power. (See Note 1 of Notes to Consolidated Financial Statements for further discussion of reporting segments.)

Unless indicated otherwise, the following discussion of critical accounting estimates, discussion and analysis of 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 2006

Our plan for 2006 was focused on continued disciplined growth. Objectives and highlights of this plan included:

Objectives	Highlights
Continuing to improve both EVA® and segment profit.	2006 segment profit increased $185.8 million to $1,468.3 million, which contributed to improving our EVA®.
Investing in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.	Total capital expenditures were approximately $2.5 billion, of which approximately $1.4 billion was invested in Exploration & Production.
Continuing to increase natural gas production in a responsible and efficient manner.	Exploration & Production increased its average daily production by approximately 21% over last year and also added 597 billion cubic feet equivalent in net reserves during 2006. Additionally, we received 2006 industry awards including Hydrocarbon Producer of the Year and North America s Best Field Rejuvenation.
Accelerating additional asset transactions between us and Williams Partners L.P., our master limited partnership.	Williams Partners L.P. acquired 100 percent of Williams Four Corners LLC for a total of $1.583 billion.
Increasing the scale of our gathering and processing business in key growth basins.	We invested approximately $257 million in capital expenditures in Midstream including Deepwater Gulf expansion projects and completing the expansion of our Opal gas processing facility.
Filing new rates to enable our Gas Pipeline segment to create additional value.	Northwest Pipeline and Transco each filed a general rate case with the Federal Energy Regulatory Commission (FERC).
	In January 2007, Northwest Pipeline reached a settlement in its pending rate case. The settlement is subject to FERC approval, which is expected by mid-2007.

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Objectives	Highlights
Executing power contracts that reduce risk while adding new business and strengthening future cash flow potential.	During 2006, Power completed several new power sales contracts that increase the value of the portfolio and provide additional cash-flow certainty in future periods. Additionally, in early 2007, Power executed power sales agreements in southern California through 2011.

Our 2006 *income from continuing operations* increased to $332.8 million, as compared to $317.4 million in 2005. Our *net cash provided by operating activities* was $1,889.6 million in 2006 compared to $1,449.9 million in 2005. These comparative results reflect the benefit of strong natural gas liquid margins partially offset with resolution of certain legacy litigation issues. In addition to achieving these results, the following represent significant actions or events that occurred during the year:

Recent Events

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after Williams Partners L.P. successfully closed a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

In December 2006, Northwest Pipeline completed and placed into service its capacity replacement project in the state of Washington. The project involved abandoning 268 miles of 26-inch pipeline and replacing it with approximately 80 miles of 36-inch pipeline constructed in four sections along the same pipeline corridor. Additionally, Northwest Pipeline modified five existing compressor stations and created additional net horsepower.

Northwest Pipeline and Transco have each filed a general rate case with the FERC. Northwest Pipeline reached a settlement in its pending rate case. The settlement is subject to FERC approval, which is expected by mid-2007. The new rates for Northwest Pipeline are effective in January 2007, subject to refund. The new rates for Transco are expected to be effective in March 2007, subject to refund.

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Transco completed an offer to exchange all of these notes for substantially identical notes registered under the Securities Act of 1933, as amended.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In May 2006, we replaced our $1.275 billion secured revolving credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and financial covenants as the secured facility, but contains certain additional restrictions. (See Note 11 of Notes to Consolidated Financial Statements.)

In May 2006, our Board of Directors approved a regular quarterly dividend of 9 cents per share of common stock, which reflects an increase of 20 percent compared with the 7.5 cents per share paid in each of the three prior quarters.

In June 2006, Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Northwest

Pipeline completed an offer to exchange all of these notes for substantially identical notes registered under the Securities Act of 1933, as amended.

In June 2006, we reached an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000, and July 22, 2002, for a total payment of $290 million to plaintiffs. We funded our $145 million portion of the settlement with cash-on-hand in November 2006, with the balance funded directly by our insurers. We recorded a pre-tax charge for approximately $161 million in second quarter 2006. This settlement did not have a material effect on our liquidity position. (See Note 15 of Notes to Consolidated Financial Statements.)

On July 31, 2006, and August 1, 2006, we received a verdict in civil litigation related to a contractual dispute surrounding certain natural gas processing facilities known as Gulf Liquids. We recorded a pre-tax charge for approximately $88 million in second quarter 2006 related to this loss contingency. (See Note 15 of Notes to Consolidated Financial Statements.)

Our property insurance coverage levels and premiums were revised during the second quarter of 2006. In general, our coverage levels have decreased while our premiums have increased. These changes reflect general trends in our industry due to hurricane-related damages in recent years.

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 approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

Outlook for 2007

Our plan for 2007 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit.
- Invest in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.
- Continue to increase natural gas production and reserves.
- Increase the scale of our gathering and processing business in key growth basins.
- Successfully resolving the rate cases for both Northwest Pipeline and Transco.
- Execute power contracts that offset a significant percentage of our financial obligations associated with our tolling agreements.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;

Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements);

General economic and industry downturn.

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 our desired level of at least $1 billion in liquidity from cash and revolving credit facilities.

New Accounting Standards and Emerging Issues

Accounting standards that have been issued and are not yet effective may have a material effect on our Consolidated Financial Statements in the future. These include:

SFAS No. 157 Fair Value Measurements (SFAS 157). The effective date for this Statement is for fiscal years beginning after November 15, 2007. We will assess the impact on our Consolidated Financial Statements.

FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48).

FIN 48 prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

We adopted FIN 48 as of January 1, 2007. The cumulative effect of applying the Interpretation will be reported as an adjustment to the opening balance of retained earnings. The net impact of the cumulative effect of adopting FIN 48 is expected to be in the range of a $10 million to $20 million decrease in retained earnings.

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

Critical Accounting Estimates

The preparation of financial statements, in conformity with generally accepted accounting principles, requires management to make estimates and assumptions that affect the reported amounts therein. 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.

Revenue Recognition Derivative Instruments and Hedging Activities

We hold a substantial portfolio of energy trading and nontrading contracts for a variety of purposes. We review these contracts to determine whether they are nonderivatives or derivatives. If they are derivatives, we further assess whether the contracts qualify for either cash flow hedge accounting or the normal purchases and normal sales exception.

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 achieving offsetting 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 that are designated as cash flow hedges, we do not reflect changes in their fair value in earnings until the associated hedged item affects earnings. For those that have not been designated as hedges or do not qualify for hedge accounting, we recognize the net change in their fair value in income currently (marked to market).

For derivatives that are designated as cash flow hedges, 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 must also reclass 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 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.

The fair value of derivative contracts is determined based on the nature of the transaction and the market in which transactions are executed. We also incorporate assumptions and judgments about counterparty performance and credit considerations in our determination of their fair value. Contracts are executed in the following environments:

- Organized commodity exchange or over-the-counter markets with quoted prices;
- Organized commodity exchange or over-the-counter markets with quoted market prices but limited price transparency, requiring increased judgment to determine fair value;
- Markets without quoted market prices.

The number of transactions executed without quoted market prices is limited. We estimate the fair value of these contracts by using readily available price quotes in similar markets and other market analyses. The fair value of all derivative contracts is continually subject to change as the underlying commodity market changes and our assumptions and judgments change.

Additional discussion of the accounting for energy contracts at fair value is included in Energy Trading Activities within Item 7 and Note 1 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, 99.9 percent of our reserve estimates are either audited or prepared by independent experts. The data may change substantially over time as a result of numerous factors, including additional development 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. A revision of our reserve estimates within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties or goodwill. However, reserve estimate revisions would impact our depreciation and depletion expense prospectively. For example, a change of approximately 10 percent in oil and gas reserves for each basin would change our annual *depreciation, depletion and amortization* expense between approximately $25 million and $31 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. An unfavorable change in the forward price curve within reasonably likely parameters is not expected to result in an impairment of our oil and gas properties 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 reflected in income in the period in which 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 15 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, 2006, we have approximately $926 million of deferred tax assets for which a $36 million valuation allowance has been established. When assessing the need for a valuation allowance, we considered 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. Based on our projections, we believe that it is probable that we can utilize our year-end 2006 federal tax net operating losses carryovers and charitable contribution carryovers prior to their expiration. We do not expect to be able to utilize $36 million of foreign deferred tax assets related to carryovers. See Note 5 of Notes to Consolidated Financial Statements for additional information regarding the 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. In evaluating the liability associated with our various filing positions, we record a liability for probable tax contingencies. The ultimate disposition of these contingencies could have a significant impact on 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.

Pension and Postretirement Obligations

We have employee benefit plans that include pension and other postretirement benefits. Pension and other postretirement benefit plan expense and obligations are calculated by a third-party actuary and are impacted by various estimates and assumptions. These estimates and assumptions include the expected long-term rates of return

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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 pension and other postretirement 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	$ (12)	$ 14	$ (129)	$ 151
Expected long-term rate of return on plan assets	(10)	10		
Rate of compensation increase	2	(2)	14	(13)
Other postretirement benefits:				
Discount rate	(1)	1	(41)	47
Expected long-term rate of return on plan assets	(2)	2		
Assumed health care cost trend rate	6	(5)	61	(48)

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 the capital market projections provided by our independent investment consultant for the asset classifications in which the portfolio is invested as well as the target weightings of each asset classification. These rates are impacted by changes in general market conditions, but because they are long-term in nature, short-term market swings do not significantly impact the rates. Changes to our target asset allocation would also impact these rates. Our expected long-term rate of return on plan assets used for our pension plans is 7.75 percent for 2006 and was 8.5 percent from 2002-2005. Over the past ten years, our actual average return on plan assets for our pension plans has been approximately 7.9 percent.

The discount rates are used to discount future benefit cash flows to today s dollars. Decreases in these rates increase the obligation and, generally, increase the related expense. The discount rates for our pension and other postretirement benefit plans were 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 corporate bonds.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes 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.

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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, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Years ended December 31,						
	2006 (Millions)	$ Change from 2005(1)	% Change from 2005(1)	2005 (Millions)	$ Change from 2004(1)	% Change from 2004(1)	2004 (Millions)
Revenues	$ 11,812.9	$ 770.7	−6%	$ 12,583.6	$ +122.3	+1%	$ 12,461.3
Costs and expenses:							
Costs and operating expenses	9,973.6	+897.4	+8%	10,871.0	−119.3	−1%	10,751.7
Selling, general and administrative expenses	449.2	−123.8	−38%	325.4	+30.1	+8%	355.5
Other (income) expense net	20.7	+40.5	+66%	61.2	−112.8	NM	(51.6)
General corporate expenses	132.1	+13.4	+9%	145.5	−25.7	−21%	119.8
Securities litigation settlement and related costs	167.3	−157.9	NM	9.4	−9.4	NM	
Total costs and expenses	10,742.9			11,412.5			11,175.4
Operating income	1,070.0			1,171.1			1,285.9
Interest accrued net	(658.9)	+5.6	+1%	(664.5)	+163.2	+20%	(827.7)
Investing income	173.0	+149.3	NM	23.7	−24.3	−51%	48.0
Early debt retirement costs	(31.4)	−31.0	NM	(.4)	+281.7	+100%	(282.1)
Minority interest in income of consolidated subsidiaries	(40.0)	−14.3	−56%	(25.7)	−4.3	−20%	(21.4)
Other income net	26.4	−0.7	−3%	27.1	+5.3	+24%	21.8
Income from continuing operations before income taxes	539.1			531.3			224.5

and cumulative effect of change in accounting principle										
Provision for income taxes		206.3	+7.6	+4%		213.9	−82.6	−63%		131.3
Income from continuing operations		332.8				317.4				93.2
Income (loss) from discontinued operations		(24.3)	−22.2	NM		(2.1)	−72.6	NM		70.5
Income before cumulative effect of change in accounting principle		308.5				315.3				163.7
Cumulative effect of change in accounting principle			+1.7	+100%		(1.7)	−1.7	NM		
Net income	$	308.5			$	313.6			$	163.7

(1) + = 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.

2006 vs. 2005

The decrease in *revenues* is primarily due to lower power and natural gas realized revenues at Power. These revenues declined due to lower sales volumes associated with reducing the scope of our trading activities and lower natural gas sales prices. Partially offsetting these decreases are increased crude, olefin and natural gas liquid (NGL) marketing revenues and higher NGL production revenue at Midstream and increased production revenue at Exploration & Production.

The decrease in *costs and operating expenses* is largely due to decreased power purchase volumes and reduced natural gas purchase prices at Power. Partially offsetting these decreases are increased crude, olefin and NGL marketing purchases and operating expenses at Midstream and increased depreciation, depletion and amortization and lease operating expense at Exploration & Production.

The increase in *selling, general and administrative (SG&A) expenses* is primarily due to increased personnel costs, insurance expense, higher information systems support costs and the absence of a $17.1 million reduction of pension expense at Gas Pipeline in 2005. Additionally, Exploration & Production experienced higher costs due to increased staffing in support of increased drilling and operational activity.

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

- A $72.7 million accrual for a Gulf Liquids litigation contingency;
- Income of $12.7 million due to reducing contingent obligations associated with our former distributive power generation business at Power;
- Income of $9 million due to a settlement of an international contract dispute at Midstream;

Other (income) expense — net within *operating income* in 2005 includes:

- An $82.2 million accrual for litigation contingencies at Power, associated primarily with agreements reached to substantially resolve exposure related to certain natural gas price and volume reporting issues;
- Gains totaling $29.6 million on the sale of certain natural gas properties at Exploration & Production;
- A gain of $9 million on a sale of land in our Other segment.

General corporate expenses decreased primarily due to the absence of $13.8 million of insurance settlement charges in 2005 associated with certain insurance coverage allocation issues.

The *securities litigation settlement and related costs* is the result of settling class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002.

Interest accrued — net in 2006 includes $22 million in interest expense associated with our Gulf Liquids litigation contingency.

The increase in *investing income* is due to:

- The absence of an $87.2 million impairment in 2005 on our investment in Longhorn Partners Pipeline, L.P. (Longhorn);
- The absence of a $23 million impairment in 2005 of our Aux Sable Liquid Products, L.P. (Aux Sable) equity investment;
- An approximate $37 million increase in interest income primarily associated with increased earnings on cash and cash equivalent balances associated with higher rates of return;
- Increased equity earnings of $33.3 million due largely to the absence of equity losses in 2006 on Longhorn and increased earnings of our Discovery Producer Services LLC (Discovery) and Aux Sable investments;

These increases are partially offset by:

A $16.4 million impairment of a Venezuelan cost-based investment at Exploration & Production;

The absence of an $8.6 million gain on sale of our remaining Mid-America Pipeline (MAPL) and Seminole Pipeline (Seminole) investments at Midstream in 2005.

Early debt retirement costs in 2006 includes $25.8 million in premiums and $1.2 million in fees related to the January 2006 debt conversion and $4.4 million of accelerated amortization of debt expenses related to the retirement of the debt secured by assets of Williams Production RMT Company.

The increase in *minority interest in income of consolidated subsidiaries* is primarily due to the growth of Williams Partners L.P., our consolidated master limited partnership.

Provision for income taxes changed favorably during the year. The effective income tax rate for 2006 is slightly higher than the federal statutory rate primarily due to state income taxes, the effect of taxes on foreign operations, nondeductible convertible debenture expenses and an accrual for income tax contingencies, partially offset by the favorable resolution of federal income tax litigation and the utilization of charitable contribution carryovers not previously benefited. The 2006 effective income tax rate has been increased by an adjustment to increase overall deferred income tax liabilities. The effective income tax rate for 2005 is higher than the federal statutory rate due primarily to state income taxes, nondeductible expenses, the effect of taxes on foreign operations and the inability to utilize charitable contribution carryovers. The 2005 effective income tax rate was reduced by an adjustment to reduce overall deferred income tax liabilities and favorable settlements on federal and state income tax matters. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2006 includes:

An $11.9 million net-of-tax litigation settlement related to our former chemical fertilizer business;

A $3.7 million net-of-tax charge associated with the settlement of a loss contingency related to a former exploration business;

A $9.1 million net-of-tax charge associated with an oil purchase contract related to our former Alaska refinery.

Cumulative effect of change in accounting principle in 2005 is due to the implementation of FIN 47. (See Note 9 of Notes to Consolidated Financial Statements.)

2005 vs. 2004

The increase in revenues is due primarily to increased revenues at Exploration & Production due to higher natural gas prices and production volumes sold and gas management income, and at Midstream due primarily to increased NGL prices and crude marketing revenue. Partially offsetting these increases is decreased revenue at Power due primarily to the absence of crude and refined products activity and reduced net forward unrealized mark-to-market gains.

The increase in *costs and operating expenses* is due primarily to increased crude marketing costs and increased NGL costs at Midstream in addition to increased depreciation, depletion and amortization and gas management expense at Exploration & Production. Partially offsetting these increases are decreased costs at Power primarily due to the absence of crude and refined products activity.

The decrease in *SG&A expenses* is primarily due to the $17.1 million reduction in expenses at Gas Pipeline to record the cumulative impact of a correction to pension expense attributable to the periods 2003 and 2004 and a $9.7 reduction of bad debt expense at Power resulting from the sale of certain receivables to a third party. Partially offsetting these items is increased staffing costs at Exploration & Production in support of increased operational drilling activity.

Other (income) expense net, within *operating income,* in 2004 includes:

Income of $93.6 million from an insurance arbitration award associated with Gulf Liquids at Midstream;

Gains of $16.2 million from the sale of Exploration & Production s securities, invested in a coal seam royalty trust, that were purchased for resale;

A $9.5 million gain on the sale of Louisiana olefins assets at Midstream;

A $15.4 million loss provision related to an ownership dispute on prior period production included at Exploration & Production;

An $11.8 million environmental expense accrual related to the Augusta refinery facility included in our Other segment;

A $9 million write-off of previously capitalized costs on an idled segment of Northwest Pipeline s system included at Gas Pipeline.

The increase in *general corporate expenses* is due primarily to the $13.8 million of expense related to the settlement of certain insurance coverage issues and a $16 million increase in outside legal costs associated primarily with securities class action matters.

The decrease in *interest accrued net* is due primarily to lower average borrowing levels in 2005 as compared to 2004.

The decrease in *investing income* is due primarily to a $76.4 increase in impairment charges on our investment in Longhorn, a $13.9 million increase in Longhorn equity losses, and the $23 million impairment of our Aux Sable equity investment. Partially offsetting these decreases are the following increases:

A $30.4 million increase in domestic and international equity earnings, excluding Longhorn and Aux Sable;

The absence in 2005 of a $20.8 million impairment of an international cost-based investment;

The absence in 2005 of a $16.9 million impairment of our Discovery equity investment;

The $8.6 million gain on the sale of our remaining interests in the MAPL and Seminole assets;

The absence in 2005 of a $6.5 million Longhorn recapitalization fee.

Early debt retirement costs include premiums, fees and expenses related to the retirement of debt.

Provision for income taxes changed unfavorably primarily due to increased pre-tax income in 2005 as compared to 2004. The effective income tax rate for 2005 is higher than the federal statutory rate due primarily to state income taxes, nondeductible expenses, the effect of taxes on foreign operations and the inability to utilize charitable contribution carryovers. The 2005 effective income tax rate has been reduced by an adjustment to reduce the overall deferred income tax liabilities and favorable settlements on federal and state income tax matters. The effective income tax rate for 2004 is higher than the federal statutory rate due primarily to state income taxes, a charge associated with charitable contribution carryovers and the effect of taxes on foreign operations. A 2004 accrual for income tax contingencies was offset by favorable settlements of certain federal and state income tax matters. (See Note 5 of Notes to Consolidated Financial Statements.)

Income (loss) from discontinued operations in 2004 is comprised of gains on the sales of the Canadian straddle plants and the Alaska refinery of $189.8 million and $3.6 million, respectively, as well as $22 million in income from our Canadian straddles discontinued operation. Partially offsetting these are $153 million of charges to increase our accrued liability associated with certain Quality Bank litigation matters.

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Results of Operations Segments

We are currently organized into the following segments: Exploration & Production, Gas Pipeline, Midstream, Power, and Other. Other primarily consists of corporate operations. Our management currently evaluates performance based on segment profit (loss) from operations. (See Note 17 of Notes to Consolidated Financial Statements.)

Exploration & Production

Overview of 2006

In 2006, we focused on our objective to rapidly expand development of our drilling inventory. This resulted in significant growth as evidenced by the following accomplishments:

- We increased average daily domestic production levels by approximately 23 percent over last year, surpassing our goal of 15 to 20 percent. The average daily domestic production was approximately 752 million cubic feet of gas equivalent (MMcfe) compared to 612 MMcfe in 2005. The increased production is primarily due to increased development within the Piceance and Powder River basins.

Domestic Production

2006 domestic production grew 23 percent or 140 MMcfe per day over 2005

- We continued to increase our development drilling program during 2006. We drilled 1,783 gross wells in 2006 compared to 1,627 in 2005. This contributed to the addition of 597 billion cubic feet equivalent (Bcfe) in net reserves a replacement rate for our domestic production of 216 percent in 2006 compared to 277 percent in 2005. Capital expenditures for domestic drilling, development, gathering facilities and acquisition activity in 2006 were approximately $1.4 billion compared to approximately $768 million in 2005.

The benefit of higher production volumes to operating results was more than offset by the downward trending of natural gas market prices during the year and increased operating costs. The increase in operating costs reflects an increase in our production volumes combined with a general industry condition of greater demand for services and products as production activities increase in our key basins.

Significant events

At December 31, 2006, all ten new state-of-the-art FlexRig4® drilling rigs have been placed into service pursuant to our lease agreement with Helmerich & Payne. The March 2005 contract provided for the operation of the drilling rigs, each for a primary lease term of three years. This arrangement supports our continuing objective to accelerate the pace of natural gas development in the Piceance basin through both deployment of the additional rigs and through the drilling and operational efficiencies of the new rigs.

In 2006, we increased our position in the Fort Worth basin by acquiring producing properties and undeveloped leasehold interests for approximately $64 million. These acquisitions increased our diversification into the Mid-Continent region and will allow us to use our horizontal drilling expertise to develop wells in the Barnett Shale formation.

Outlook for 2007

Our expectations and objectives for 2007 include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through planned capital expenditures of $1.3 to $1.4 billion.

- Continuing to grow our domestic average daily production level with a goal of 10 to 20 percent annual growth.

Approximately 172 MMcfe, or 18 percent, of our forecasted 2007 daily production is hedged by NYMEX and basis fixed price contracts at prices that average $3.90 per Mcfe at a basin level. In addition, we have collar agreements for each month in 2007 as follows:

- NYMEX collar agreement for approximately 15 MMcfe per day at a weighted-average floor price of $6.50 per Mcfe and a weighted-average ceiling price of $8.25 per Mcfe.

- Northwest Pipeline/Rockies collar agreement for approximately 50 MMcfe per day at a floor price of $5.65 per Mcfe and a ceiling price of $7.45 per Mcfe at a basin level.

- El Paso/San Juan collar agreements totaling approximately 130 MMcfe per day at a weighted average floor price of $5.98 per Mcfe and a weighted average ceiling price of $9.63 per Mcfe at a basin level.

- Mid-Continent (PEPL) collar agreements totaling approximately 75 MMcfe per day at a weighted average floor price of $6.82 per Mcfe and a weighted average ceiling price of $10.80 per Mcfe at a basin level.

We have recently 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 and on natural gas reserves value.

Additional risks to achieving our expectations include weather conditions at certain of our locations during the first and fourth quarters of 2007, drilling rig availability, obtaining permits as planned for drilling, and market price movements.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2006	2005	2004
		(Millions)	

Segment revenues	$ 1,487.6	$ 1,269.1	$ 777.6
Segment profit	$ 551.5	$ 587.2	$ 235.8

2006 vs. 2005

Total *segment revenues* increased $218.5 million, or 17 percent, primarily due to the following:

$165 million, or 15 percent, increase in domestic production revenues reflecting $245 million primarily associated with a 23 percent increase in natural gas production volumes sold, offset by a decrease of $80 million associated with a 6 percent decrease in net realized average prices. The increase in production volumes is primarily from the Piceance and Powder River basins and the decrease in prices reflects the downward trending of market prices in the latter part of 2006.

$10 million increase in production revenues from our international operations primarily due to increases in net realized average prices for crude oil production volumes sold.

$14 million of net unrealized gains in 2006 from hedge ineffectiveness and forward mark-to-market gains on certain basis swaps not designated as hedges as compared to $10 million in net unrealized losses attributable to hedge ineffectiveness from NYMEX collars in 2005.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative sales contracts that fix the sales price relating to a portion of our future production. Approximately 40 percent of domestic production in 2006 was hedged by NYMEX and basis fixed price contracts at a weighted average price of $3.82 per Mcfe at a basin level compared to 47 percent hedged at a weighted average price of $3.99 per Mcfe in 2005. In addition, approximately 15 percent of domestic production was hedged by the following collar agreements in 2006:

NYMEX collar agreement for approximately 49 MMcfe per day at a floor price of $6.50 per Mcfe and a ceiling price of $8.25 per Mcfe.

NYMEX collar agreement for approximately 15 MMcfe per day at a floor price of $7.00 per Mcfe and a ceiling price of $9.00 per Mcfe.

Northwest Pipeline/Rockies collar agreement for approximately 50 MMcfe per day at a floor price of $6.05 per Mcfe and a ceiling price of $7.90 per Mcfe at a basin level.

In 2005, approximately 10 percent of domestic production was hedged by a NYMEX collar agreement for approximately 50 MMcfe per day at a floor price of $7.50 per Mcfe and a ceiling price of $10.49 per Mcfe in the first quarter and at a floor price of $6.75 per Mcfe and a ceiling price of $8.50 per Mcfe in the second, third, and fourth quarters, and a Northwest Pipeline/Rockies collar agreement for approximately 50 MMcfe per day in the fourth quarter at a floor price of $6.10 per Mcfe and a ceiling price of $7.70 per Mcfe.

Our hedges are executed with our Power segment, which, in turn, executes offsetting derivative contracts with unrelated third parties. Generally, Power bears the counterparty performance risks associated with unrelated third parties. Hedging decisions are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

Total *costs and expenses* increased $257 million, primarily due to the following:

$107 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$54 million higher lease operating expense primarily due to the increased number of producing wells and higher well service and industry costs due to increased demand and approximately $6 million for out-of-period expenses related to 2005. Our management has concluded that the effect of this item is not material to our consolidated results for 2006, or prior periods, or to our trend of earnings;

$19 million higher operating taxes primarily due to higher production volumes sold and increased tax rates;

$33 million higher selling, general and administrative expenses primarily due to higher compensation for additional staffing in support of increased drilling and operational activity. In addition, we incurred higher legal, insurance, and information technology support costs related to the increased activity;

The absence in 2006 of $29.6 million of gains on the sales of properties in 2005.

The $35.7 million decrease in s*egment profit* is primarily due to lower net realized average prices and higher *costs and expenses* as discussed previously, and the absence in 2006 of $29.6 million of gains on the sales of properties in 2005. Partially offsetting these decreases are a 23 percent increase in domestic production volumes sold and an increase in income from ineffectiveness and forward mark-to-market gains. *Segment profit* also includes an $8 million increase in our international operations primarily due to higher revenue and equity earnings as a result of increases in net realized average prices for crude oil production volumes sold.

2005 vs. 2004

The $491.5 million, or 63 percent increase in *segment revenues* is primarily due to an increase in domestic production revenues of $434 million during 2005 reflecting higher net realized average prices and higher production volumes sold. Also contributing to the increase is a $58 million increase in revenues from gas management activities, offset in *costs and expenses*, and $13 million increased production revenues from our international operations. Partially offsetting these increases is $10 million in net unrealized losses attributable to NYMEX collars from hedge ineffectiveness.

The increase in domestic production revenues primarily results from $319 million higher revenues associated with a 42 percent increase in net realized average prices for production sold as well as a $115 million increase associated with an 18 percent increase in average daily production volumes. The higher net realized average prices reflect the benefit of the lower volumes hedged in 2005 as compared to 2004 coupled with higher market prices for natural gas in 2005. The increase in production volumes primarily reflects an increase in the number of producing wells resulting from our successful 2005 drilling program.

Approximately 77 percent of domestic production in 2004 was hedged at a weighted average price of $3.65 per Mcfe at a basin level.

Total *costs and expenses* increased $147 million, primarily due to the following:

- $62 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

- $16 million higher lease operating expense from the increased number of producing wells and generally higher industry costs;

- $23 million higher operating taxes primarily due to increased market prices and production volumes sold;

- $18 million higher selling, general and administrative expenses primarily due to higher compensation and increased staffing in 2005 in support of increased drilling and operational activity;

- $58 million higher gas management expenses associated with higher revenues from gas management activities, offset in *segment revenues*;

- $11 million lower gain in 2005 than in 2004 on the sale of securities associated with our coal seam royalty trust that were previously purchased for resale.

These increased *costs and expenses* are partially offset by the absence in 2005 of a $15.4 million loss provision related to an ownership dispute on prior period production in 2004, a $7.9 million gain on the sale of an undeveloped leasehold position in Colorado in the first quarter of 2005, and a $21.7 million gain on the sale of certain outside operated properties in the Powder River basin area of Wyoming in the third quarter of 2005.

The $351.4 million increase in s*egment profit* is primarily due to increased revenues from higher volumes and higher net realized average prices, as well as the gains on sales of assets, partially offset by higher expenses as discussed above. *Segment profit* also includes a $19 million increase in our international operations reflecting higher revenue and equity earnings resulting from higher net realized oil and gas prices.

Gas Pipeline

Overview

We operate, through our Northwest Pipeline and Transco subsidiaries, approximately 14,400 miles of pipeline from the Gulf Coast to the northeast United States and from northern New Mexico to the Pacific Northwest with a total annual throughput of approximately 2,500 trillion BTUs. Additionally, we hold a 50 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream). This asset, which extends from the Mobile Bay area in Alabama to markets in Florida, has current transportation capacity of 1.1 MMdt/d.

Our strategy to create value for our shareholders 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 impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Significant events of 2006 include:

Filing of rate cases

During 2006, Northwest Pipeline and Transco each filed general rate cases with the FERC for increases in rates due to higher costs in recent years. The new rates are effective, subject to refund, in January 2007 for Northwest Pipeline and in March 2007 for Transco. We expect the new rates to result in significantly higher revenues.

In January 2007, Northwest Pipeline reached a settlement in its pending rate case. The settlement is subject to FERC approval, which is expected by mid-2007.

Gulfstream

In March 2006, our equity method investee, Gulfstream, announced a new long-term agreement with a Florida utility company, which fully subscribed the pipeline s mainline capacity on a long-term basis. Under the agreement, Gulfstream will extend its existing pipeline approximately 35 miles within Florida. The agreement is subject to the approval of various authorities. Construction of the extension is anticipated to begin in early 2008 with a targeted completion of summer 2008.

In May 2006, Gulfstream announced a new agreement to provide 155 Mdt/d of natural gas to a Florida utility. In December 2006, Gulfstream filed an application with the FERC seeking approval to expand its pipeline system to provide the additional capacity. Under this agreement, Gulfstream will construct approximately 17.5 miles of 20 inch pipeline and the installation of a new compressor facility. If approved, all of the facilities will be placed into service by January 2009.

Parachute Lateral project

In August 2006, we received FERC approval to construct a 37.6-mile expansion that will provide additional natural gas transportation capacity in northwest Colorado. The planned expansion will increase capacity by 450 Mdt/d through the 30-inch diameter line and is estimated to cost approximately $86 million. The expansion is expected to be in service in March 2007.

Grays Harbor

Effective January 2005, Duke Energy Trading and Marketing, LLC (Duke) terminated its firm transportation agreement related to Northwest Pipeline s Grays Harbor lateral. In January 2005, Duke paid Northwest Pipeline $94 million for the remaining book value of the asset and the related income taxes. We and Duke have not agreed on the amount of the income taxes due Northwest Pipeline as a result of the contract termination. We have deferred the $6 million difference between the proceeds and net book value of the lateral pending resolution of the disputed early termination obligation.

On June 16, 2005, we filed a Petition for a Declaratory Order with the FERC requesting that it rule on our interpretation of our tariff to aid in resolving the dispute with Duke. On July 15, 2005, Duke filed a motion to intervene and provided comments supporting its position concerning the issues in dispute.

On October 4, 2006, the FERC issued its Order on Petition for Declaratory Order, providing clarification on issues relating to Duke s obligation to reimburse us for future tax expenses. We reviewed the Order and filed a request for rehearing requesting further clarification of certain items. Based upon the order, as written, we do not anticipate any adverse impact to our results of operations or financial position.

Northwest Pipeline capacity replacement project

In September 2005, we received FERC approval to construct and operate approximately 80 miles of 36-inch pipeline loop as a replacement for most of the capacity previously served by 268 miles of 26-inch pipeline in the Washington state area. The capacity replacement as well as the abandonment of the old capacity was completed in December 2006. In addition to the capacity replacement, five existing compressor stations were modified, and we increased net horsepower.

Outlook for 2007

Leidy to Long Island expansion project

In May 2006, we received FERC approval to expand Transco s natural gas pipeline in the northeast United States. The estimated cost of the project is approximately $141 million with three-quarters of that spending expected to occur in 2007. The expansion will provide 100 Mdt/d of incremental firm capacity and is expected to be in service by November 2007.

Potomac expansion project

In July 2006, we filed an application with the FERC to expand Transco s existing facilities in the Mid-Atlantic region of the United States by constructing 16.5 miles of 42-inch pipeline. The project will provide 165 Mdt/d of incremental firm capacity. The estimated cost of the project is approximately $74 million, with an anticipated in-service date of November 2007.

Year-Over-Year Operating Results

	Years Ended December 31,		
	2006	2005	2004
		(Millions)	
Segment revenues	$ 1,347.7	$ 1,412.8	$ 1,362.3
Segment profit	$ 467.4	$ 585.8	$ 585.8

Significant 2005 adjustments

Operating results for 2005 included:

Adjustments of $17.7 million reflected as a $12.1 million reduction of *costs and operating expenses* and a $5.6 million reduction of *SG&A expenses*. These cost reductions were corrections of the carrying value of certain liabilities that were recorded in prior periods. Based on a review by management, these liabilities were no longer required.

Pension expense reduction of $17.1 million in the second quarter of 2005 to reflect the cumulative impact of a correction of an error attributable to 2003 and 2004. The error was associated with our third-party actuarial computation of annual net periodic pension expense and resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004.

Adjustments of $37.3 million reflected as increases in *costs and operating expenses* related to $32.1 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5.2 million for contingent refund obligations.

Our management concluded that the effects of these adjustments were not material to our consolidated results for 2005 or prior periods, or to our trend of earnings.

2006 vs. 2005

Revenues decreased $65.1 million, or 5 percent, due primarily to $75 million lower revenues associated with exchange imbalance settlements (offset in *costs and operating expenses*). Partially offsetting this decrease is a $9 million increase in revenue due to an adjustment for the recovery of state income tax rate changes (offset in *provision for income taxes*).

Costs and operating expenses decreased $17 million, or 2 percent, due primarily to:

A decrease in costs of $75 million associated with exchange imbalance settlements (offset in *revenues*);

A decrease in costs of $37.3 million related to the absence of $32.1 million of 2005 prior period accounting and valuation corrections for certain inventory items and an accrual of $5.2 million for contingent refund obligations.

Partially offsetting these decreases are:

An increase in contract and outside service costs of $23 million due primarily to higher pipeline assessment and repair costs;

An increase in depreciation expense of $15 million due to property additions;

An increase in operating and maintenance expenses of $15 million;

An increase in operating taxes of $10 million;

The absence of $14.2 million of income in 2005 associated with the resolution of litigation;

The absence of $12.1 million of expense reductions during 2005 related to the carrying value of certain liabilities.

SG&A expenses increased $77 million, or 92 percent, due primarily to:

An increase in personnel costs of $18 million;

The absence of a 2005 $17.1 million reduction in pension costs to correct an error in prior periods;

An increase in information systems support costs of $16 million;

An increase in property insurance expenses of $14 million;

The absence of $5.6 million of cost reductions in 2005 that related to correcting the carrying value of certain liabilities.

The $118.4 million, or 20 percent, decrease in *segment profit* is due primarily to the absence of significant 2005 adjustments as previously discussed, increases in *costs and operating expenses* and *SG&A expenses* as previously discussed, and the absence of a $4.6 million construction completion fee recognized in 2005 related to our investment in Gulfstream.

2005 vs. 2004

The $50.5 million, or 4 percent, increase in Gas Pipeline *revenues* is due primarily to $86 million higher revenues associated with exchange imbalance cash-out settlements (offset in *costs and operating expenses*). Partially offsetting this increase is $24 million lower transportation revenues due primarily to the termination of the Grays Harbor contract, and $11 million lower revenues associated with reimbursable costs, which are passed through to customers (offset in *costs and operating expenses* and *SG&A expenses*).

Costs and operating expenses increased $109 million, or 16 percent, due primarily to:

- An increase in costs of $86 million associated with exchange imbalances (offset in *revenues*);
- The increase in costs of $32.1 million due to prior period accounting and valuation corrections related to inventory, as previously discussed;
- An increase in operating and maintenance expense of $14 million due primarily to increased contract service costs, materials and supplies and rental fees;
- The increase in costs of $5.2 million due to an accrual for contingent refund obligations, as previously discussed.

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Partially offsetting these increases are decreases due to:

Income of $14.2 million associated with the resolution of the litigation related to recovery of gas costs;

The cost reduction of $12.1 million due to adjusting the carrying value of certain liabilities, as previously discussed;

Lower reimbursable costs of $5 million (offset in *revenues*).

SG&A expenses decreased approximately $38 million, or 31 percent, due to the $17.1 million reduction in pension costs to correct a prior period error, $6 million lower reimbursable costs (offset in *revenues*), and the reversal of $5.6 million of prior period accruals.

Comparative *segment profit* is unchanged from 2004. The following are significant components of 2005 segment profit:

The reduction in pension costs of $17.1 million to correct a prior period error, as previously discussed;

An increase in Gulfstream equity earnings of $14 million due to the realization of a $4.6 million construction fee award on the completion of the Phase II expansion project coupled with increased revenues associated with the Gulfstream expansions;

Income of $14.2 million from the reversal of the contingency related to recovery of gas costs;

The $17.7 million reversal of prior period accruals;

The increase in costs of $32.1 million due to prior period accounting and valuation corrections related to inventory;

An increase in operating and maintenance expense of $14 million due primarily to increased contract service costs, materials and supplies and rental fees;

A decrease in transportation revenue of $24 million due primarily to the termination of the Grays Harbor contract.

Midstream Gas & Liquids

Overview of 2006

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. Our business is focused on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2006 included the following:

Favorable commodity price margins

The actual realized NGL per unit margins at our processing plants exceeded Midstream s rolling five-year average for the last four quarters. The geographic diversification of Midstream assets contributed significantly to our actual realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices. During 2006, NGL production rebounded from levels experienced in fourth-quarter 2005 in response to improved gas processing spreads as crude prices, which correlate to NGL prices, averaged $66 per barrel and natural gas prices decreased.

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

Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

We continued construction at our existing gas processing plant located near Opal, Wyoming, to add a fifth cryogenic train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion is being placed into service during the first quarter of 2007 to begin processing gas from the Pinedale Anticline field.

Also, we continued construction on a 37-mile extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. This extension, estimated to cost approximately $200 million, is expected to be ready for service by the second quarter of 2008.

In May 2006, we entered into an agreement to develop new pipeline capacity for transporting natural gas liquids from production areas in southwestern Wyoming to central Kansas. The other party to the agreement reimbursed us for the development costs we incurred to date for the proposed pipeline and initially will own 99 percent of the pipeline, known as Overland Pass Pipeline Company, LLC. We retained a 1 percent interest and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. Start-up is planned for early 2008. Additionally, we have agreed to dedicate our equity NGL volumes from our two Wyoming plants for transport under a long-term shipping agreement. The terms represent significant savings compared with the existing tariff and other alternatives considered.

Williams Partners L.P. acquires Four Corners gathering and processing business

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. The acquisition was completed after Williams Partners L.P. closed a $150 million private debt offering of senior unsecured notes due 2011 and an equity offering of approximately $225 million in net proceeds. In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. closed a $600 million private debt offering of senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan basin in Colorado and New Mexico.

We currently own approximately 22.5 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us. Considering the presumption of control of the general partner in accordance with EITF Issue No. 04-5, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 1 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit, with the minority interest s share deducted below segment profit. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively.

Gulf Coast operations return to normal after 2005 s hurricanes

In 2005, Hurricanes Dennis, Katrina and Rita caused temporary shut-downs of most of our facilities and our producers facilities in the Gulf Coast region, which reduced product flows in the second half of 2005. Our major facilities resumed normal operations shortly after the passage of each hurricane except for our Devils Tower spar which returned to service in early November 2005 and our Cameron Meadows gas processing plant which returned to partial service in February 2006 and achieved full service in January 2007. Generally, overall product flows returned to pre-hurricane levels during the first quarter of 2006.

Gulf Liquids litigation

We recorded pre-tax charges totalling $94.7 million resulting from jury verdicts in civil litigation. (See Note 15 of Notes to Consolidated Financial Statements.) These charges reflect our estimated exposure for actual damages of $72.7 million, including estimated legal fees of $4.7 million, and potential pre-judgment interest of $22 million. Midstream Other segment profit reflects the $72.7 million charge for the estimated actual damages and legal fees. The matter is related to a contractual dispute surrounding construction in 2000 and 2001 of certain refinery off-gas processing facilities by Gulf Liquids. In addition, it is reasonably possible that any ultimate judgment may include additional amounts of $199 million in excess of our accrual, which represents our estimate of potential punitive damage exposure under Texas law. The jury verdicts are subject to trial and appellate court review. Entry of a judgment in the trial court is expected in the second or third quarter of 2007. If the trial court enters a judgment consistent with the jury s verdicts against us, we will seek a reversal through appeal.

Outlook for 2007

The following factors could impact our business in 2007 and beyond.

As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last four quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. Forecasted domestic demand for ethylene and propylene, whose feedstock are ethane and propane, along with political instability in many of the key oil producing countries will continue to support unit margins in 2007 exceeding our rolling five-year average. We do not expect to achieve the record levels we experienced in 2006.

Margins in our olefins unit are highly dependent upon continued economic growth within the U.S. and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the U.S. Based on recent market price forecasts, we anticipate olefins unit margins to be slightly lower than 2006 levels.

Gathering and processing revenues at our facilities are expected to be at or above levels of previous years due to continued strong drilling activities in our core basins.

Revenues from deepwater production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.

We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services.

We expect continued growth in the deepwater areas of the Gulf of Mexico to contribute to, and become a larger component of, our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks. We expect revenues from our deepwater production areas to decrease as volumes decline in 2007 and increase in 2008 as the extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect is placed into service.

In 2007 we will begin construction on our Perdido Norte project which includes oil and gas lines that expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. Additionally, we will be expanding our Markham gas processing facility to adequately serve this new gas production. The project is estimated to cost approximately $480 million and be in service in the third quarter of 2009.

We are currently negotiating with our customer in Venezuela to resolve approximately $14 million in past due invoices related to labor escalation charges. The customer is not disputing the index used to calculate these charges and we have calculated the charges according to the terms of the contract. The customer does, however, believe the index has resulted in a disproportionate escalation over time. We believe the receivables, net of associated reserves, are fully collectible. Although we believe our negotiations will be successful, failure to resolve this matter could ultimately trigger default noncompliance provisions in the services agreement.

The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, continues to publicly declare that additional energy contracts will be unilaterally amended, and that privately held assets will be expropriated, indicating that a level of political risk still remains.

Year-Over-Year Results

	Years Ended December 31,		
	2006	**2005**	**2004**
		(Millions)	
Segment revenues	$ 4,124.7	$ 3,232.7	$ 2,882.6
Segment profit			
Domestic gathering & processing	626.8	379.7	385.8
Venezuela	98.4	94.7	85.6
Other	3.4	62.3	134.0
Indirect general and administrative expense	(70.3)	(65.5)	(55.7)
Total	$ 658.3	$ 471.2	$ 549.7

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.

2006 vs. 2005

The $892.0 million increase in *segment revenues* is largely due to:

A $561 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from additional deepwater production coming on-line in November 2005;

A $165 million increase in revenues associated with the production of NGLs, primarily due to higher NGL prices combined with higher volumes;

A $137 million increase in the marketing of NGLs and olefins, which is offset by a similar change in costs;

An $83 million increase in fee-based revenues including $52 million in higher production handling revenues;

A $44 million increase in revenues in our olefins unit due to higher volumes.

These increases were partially offset by an $84 million reduction in NGL revenues due to a change in classification of NGL transportation and fractionation expenses from costs of goods sold to net revenues (offset in costs and operating expenses).

Segment costs and expenses increased $707.3 million primarily as a result of:

A $561 million increase in crude marketing purchases, which is offset by a similar change in revenues;

A $137 million increase in NGL and olefins marketing purchases, offset by a similar change in revenues;

An $82 million increase in operating expenses including a $10.6 million accounts payable accrual adjustment, higher system losses, depreciation, insurance expense, personnel and related benefit expenses, turbine overhauls, materials and supplies, compression and post-hurricane inspection and survey costs required by a government agency;

A $59 million increase in other expense including the $68 million estimated exposure for actual damages for the Gulf Liquids litigation, partially offset by a $9 million favorable settlement of a contract dispute;

A $20 million increase in costs associated with production in our olefins unit.

These increases were partially offset by:

An $84 million reduction in NGL transportation and fractionation expenses due to the above-noted change in classification (offset in revenues);

A $77 million decrease in plant fuel and costs associated with the production of NGLs due primarily to lower gas prices.

The $187.1 million increase in Midstream *segment profit* is primarily due to higher NGL margins, higher deepwater production handling revenues, higher gathering and processing revenues, higher margins from our olefins unit, and a settlement of an international contract dispute, largely offset by the $72.7 million charge related to the Gulf Liquids litigation contingency combined with higher operating costs and lower margins related to the marketing of olefins and NGLs. A more detailed analysis of the *segment profit* of Midstream s various operations is presented as follows.

Domestic gathering & processing

The $247.1 million increase in *domestic gathering and processing segment profit* includes a $143 million increase in the West region and a $104 million increase in the Gulf Coast region.

The $143 million increase in our West region s *segment profit* primarily results from higher product margins and higher gathering and processing revenues, partially offset by higher operating expenses. The significant components of this increase include the following:

NGL margins increased $166 million compared to 2005. This increase was driven by a decrease in costs associated with the production of NGLs, an increase in average per unit NGL prices and higher volumes resulting from lower NGL recoveries during the fourth quarter of 2005 caused by intermittent periods of uneconomical market commodity prices and a power outage and associated operational issues at our Opal, Wyoming facility. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense.

Gathering and processing fee revenues increased $26 million. Gathering fees are higher as a result of higher average per-unit gathering rates. Processing volumes are higher due to customers electing to take liquids and pay processing fees.

Operating expenses increased $51 million including $11 million in higher net system product losses as a result of system gains in 2005 compared to losses in 2006, a $7 million accounts payable accrual adjustment; $8 million in higher personnel and related benefit expenses; $6 million in higher materials and supplies; $6 million in higher gathering fuel, $4 million in higher leased compression costs; $4 million in higher turbine overhaul costs; and $4 million in higher depreciation.

The $104 million increase in the Gulf Coast region s *segment profit* is primarily a result of higher NGL margins, higher volumes from our deepwater facilities, partially offset by higher operating expenses. The significant components of this increase include the following:

NGL margins increased $77 million compared to 2005. This increase was driven by an increase in average per unit NGL prices and a decrease in costs associated with the production of NGLs.

Fee revenues from our deepwater assets increased $52 million as a result of $51 million in higher volumes flowing across the Devils Tower facility and $22 million in higher Devils Tower unit-of-production rates recognized as a result of a new reserve study. These increases are partially offset by a $21 million decline in other gathering and production handling revenues due to volume declines in other areas.

Operating expenses increased $25 million primarily as a result of $12 million in higher insurance costs, $4 million in higher depreciation expense on our deepwater assets, $3 million in higher net system product losses as a result of lower gain volumes in 2006, $2 million in post-hurricane inspection and survey costs required by a government agency, and a $1 million accounts payable accrual adjustment.

Venezuela

Segment profit for our Venezuela assets increased $3.7 million and includes $9 million resulting from the settlement of a contract dispute and $1 million in higher revenues due to higher natural gas volumes and prices at our compression facility. These are partially offset by $4 million in higher expenses related to higher insurance, personnel and contract labor costs and a $2 million increase in the reserve for uncollectible accounts.

Other

The $58.9 million decrease in *segment profit* of our other operations is largely due to the $72.7 million of charges related to the Gulf Liquids litigation contingency combined with $13 million in lower margins related to the marketing of olefins. The decrease also reflects $12 million in lower margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2005 as compared to 2006. These were partially offset by $24 million in higher margins in our olefins unit, $7 million in higher earnings from our equity investment in Discovery Producer Services, L.L.C. (Discovery), $7 million in higher fractionation, storage and other fee revenues, and a $4 million favorable transportation settlement.

2005 vs. 2004

The $350.1 million increase in *segment revenues* is largely due to:

A $196 million increase in crude marketing revenues, which is offset by a similar change in costs, resulting from the start up of a deepwater pipeline in the second quarter of 2004;

A $72 million increase in revenues associated with production of NGLs, primarily due to $180 million in higher NGL prices partially offset by $108 million in lower sales volumes. The decline in sales volumes in our Gulf Coast region is largely due to the impact of summer hurricanes, while the decline in the West region is largely due to the higher levels of NGL rejection as well as maintenance issues with our gas processing facility at Opal, Wyoming;

A $58 million increase in the marketing of NGLs, which is offset by a similar change in costs, resulting from higher prices and additional spot sales;

A $21 million increase in fee-based revenues in part due to higher customer production volumes flowing to our West region and deepwater assets.

Costs and operating expenses increased $364.1 million primarily as a result of:

A $196 million increase in crude marketing purchases, which is offset by a similar change in revenues;

A $92 million increase in costs related to the production of NGLs as a result of $100 million in higher natural gas purchases due largely to higher prices, partially offset by lower volumes;

A $58 million increase related to the marketing of NGLs and additional spot purchases, which is offset by a similar change in revenues;

A $33 million increase in operating expenses mostly due to higher fuel expense and commodity costs associated with our NGL storage and fractionation business and higher depreciation expense.

The $78.5 million decline in Midstream *segment profit* is primarily due to the absence of the $93.6 million gain from the Gulf Liquids insurance arbitration award in 2004. The offsetting increase in segment profit is primarily due to higher fee revenues from our domestic gathering and processing and Venezuela businesses and higher earnings from our investment in the Discovery partnership, partially offset by lower NGL margins and higher operating costs. A more detailed analysis of the segment profit of Midstream s various operations is presented below.

Domestic gathering & processing

The $6.1 million decrease in *domestic gathering and processing segment profit* includes a $30 million decline in the Gulf Coast region, largely offset by a $24 million increase in the West region.

The $24 million increase in our West region s *segment profit* primarily results from higher gathering and processing fee revenues, and the absence of an asset write-down and other 2004 charges, offset partially by higher operating expenses and lower NGL margins. The significant drivers to these items are as follows:

Gathering and processing fee revenues increased $18 million primarily as a result of higher average per-unit gathering and processing rates and higher volumes in the Rocky Mountain production area due to increased drilling activity. A portion of this increase is also due to the increase in volumes subject to fee-based processing contracts.

A favorable variance due to the absence of the write-down of $7.6 million for an idle treating facility in 2004.

NGL margins decreased $6 million due to a $17 million impact from lower sales volumes resulting from lower fourth quarter 2005 NGL recoveries caused by intermittent periods of uneconomical market commodity prices and a power outage and associated operational issues at our Opal, Wyoming facility. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense. The impact of lower volumes is partially offset by an $11 million impact of higher per unit NGL margins.

The $30 million decrease in the Gulf Coast region s *segment profit* is primarily a result of higher operating and depreciation expenses and lower NGL margins. The significant components of this decline include the following:

Operating expenses increased $10 million primarily due to higher maintenance expenses related to our gathering assets, compressor overhauls, and an increase in hurricane-related costs of $2 million. Inspection and repair expenses related to the hurricanes were recorded as incurred up to the level of our insurance deductible.

Depreciation expense increased $13 million primarily due to placing in service our Devils Tower spar and associated deepwater gas and oil pipelines in May and June 2004, respectively.

NGL margins declined $14 million due to lower volumes, largely due to the impact of summer hurricanes, and the increase in natural gas prices. While revenues from the Devils Tower deepwater facility are recognized as volumes are delivered over the life of the reserves, cash payments from our customers are based on a contractual fixed fee received over a defined term. As a result, $44 million of cash received in 2005, which is included in cash flow from operations, was deferred at December 31, 2005 and will be recognized as revenue in periods subsequent to 2005. The total amount deferred for all years as of December 31, 2005 was $80 million.

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Venezuela

Segment profit for our Venezuela assets increased $9.1 million as a result of higher plant volumes and higher equity earnings from our investment in the ACCROVEN partnership. The higher equity earnings are largely due to the renegotiation of a power supply contract and the absence of 2004 legal fees associated with the Jose Terminal.

Other

The $71.7 million decrease in *segment profit* of our other operations is largely due to the absence of the $93.6 million gain from the Gulf Liquids insurance arbitration award and a $9.5 million gain on the sale of the Choctaw ethylene distribution assets in 2004 partially offset by $7 million in higher olefins and commodity margins, $6 million in higher earnings from our equity investment in the Discovery partnership, and the absence of a 2004 $16.9 million impairment charge also related to our equity investment in the Discovery partnership.

Indirect general and administrative expense

The $9.8 million unfavorable variance for our *indirect general and administrative expenses* is primarily due to higher employee expenses and administrative costs associated with the creation of Williams Partners L.P.

Power

Overview of 2006

Power s operating results for 2006 reflect an accrual gross margin loss on its nonderivative tolling contracts. Power s results in 2006 were also influenced by a decrease in forward power prices against a net long derivative position, which caused net forward unrealized mark-to-market (MTM) losses. Power s results do not reflect, however, cash flows that Power realized in 2006 from hedges for which mark-to-market gains or losses had been previously recognized.

In 2006, Power continued to focus on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio and providing services that support our natural gas businesses.

Outlook for 2007

For 2007, Power intends to service its customers needs while increasing the certainty of cash flows from its long-term tolling contracts by executing new long-term electricity and capacity sales contracts. In the first quarter of 2007, Power executed agreements to sell dispatch and tolling rights and supply natural gas in southern California for periods through 2011. These contracts mirror Power s rights under its California tolling agreement and represent up to 1,920 megawatts of power.

As Power continues to apply hedge accounting in 2007, its future earnings may be less volatile. However, not all of Power s derivative contracts qualify for hedge accounting. Application of hedge accounting requires quantitative and qualitative analysis. To qualify for hedge accounting, Power must assess derivatives for their expected effectiveness in offsetting the risk being hedged. In addition, it must assess whether the hedged forecasted transaction is probable of occurring. If Power no longer expects the hedge to be highly effective, or if it believes that the hedged forecasted transaction is no longer probable of occurring, it would discontinue hedge accounting prospectively and recognize future changes in fair value directly to earnings.

Because certain derivative contracts qualifying for hedge accounting were previously marked-to-market through earnings prior to their designation as cash flow hedges, the amounts recognized in future earnings under hedge accounting will not necessarily align with the expected cash flows to be realized from the settlement of those derivatives. For example, future earnings may reflect losses from underlying transactions, such as natural gas purchases and power sales associated with our tolling contracts, which have been hedged by derivatives. A portion of the offsetting gains from these hedges, however, has already been recognized in prior periods under mark-to-market accounting. So, while earnings in a reported period may not reflect the full amount realized from our hedges, cash flows will continue to reflect the total amount from both the hedged transactions and the hedges. In 2006, 2005 and 2004 Power had positive cash flows from operations, and expects to continue to have positive cash flows from operations in 2007.

Even with the application of hedge accounting, Power s earnings will continue to reflect mark-to-market volatility from unrealized gains and losses resulting from:

Market movements of commodity-based derivatives that represent economic hedges but which do not qualify for hedge accounting;

Ineffectiveness of cash flow hedges, primarily caused by locational differences between the hedging derivative and the hedged item or changes in the creditworthiness of counterparties;

Market movements of commodity-based derivatives that are held for trading purposes.

The fair value of Power s tolling, full requirements, transportation, storage and transmission contracts is not reflected on the balance sheet since these contracts are not derivatives. Some of these contracts have a significant negative estimated fair value and could result in future operating losses. Power s estimate of fair value may differ significantly from a third party s estimate. Power s estimate of fair value is based on internal valuation assumptions, which include assumptions of natural gas prices, electricity prices, price volatility, correlation of gas and electricity, and many other inputs. Some of these assumptions are readily available in the market, while others are not.

Key factors that may influence Power s financial condition and operating performance include:

Prices of power and natural gas, including changes in the margin between power and natural gas prices;

Changes in power and natural gas price volatility;

Changes in power and natural gas supply and demand;

Changes in the regulatory environment;

The inability of counterparties to perform under contractual obligations due to their own credit constraints;

Changes in interest rates;

Changes in market liquidity, including changes in the ability to effectively hedge commodity price risk;

The inability to apply hedge accounting.

Year-Over-Year Results

	Years Ended December 31,		
	2006	**2005**	**2004**
		(Millions)	
Realized revenues	$ 7,484.6	$ 8,921.8	$ 8,954.7
Net forward unrealized mark-to-market gains (losses)	(22.2)	172.1	304.0

Segment revenues	7,462.4	9,093.9	9,258.7
Cost of sales	7,619.8	9,150.3	9,073.3
Gross margin	(157.4)	(56.4)	185.4
Operating expenses	18.0	22.2	23.7
Selling, general and administrative expenses	62.2	64.5	83.2
Other (income) expense net	(26.8)	113.6	1.8
Segment profit (loss)	$ (210.8)	$ (256.7)	$ 76.7

2006 vs. 2005

The $1.4 billion decrease in *realized revenues* is primarily due to a decrease in power and natural gas realized revenues. Realized revenues represent (1) revenue from the sale of commodities or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts.

Power and natural gas realized revenues decreased primarily due to a 20 percent decrease in power sales volumes and a 17 percent decrease in average natural gas sales prices. Power sales volumes decreased because certain long-term physical contracts were not replaced due to reducing the scope of trading activities subsequent to 2002.

Net forward unrealized mark-to-market gains (losses) represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that have not been designated as cash flow hedges and the impact of the ineffectiveness of cash flow hedges. The effect of changes in forward prices on power contracts not designated as cash flow hedges primarily caused the $194.3 million decrease in *net forward unrealized mark-to-market gains (losses).* A 2005 increase in forward power prices caused gains on the net forward purchase position, while a 2006 decrease in forward power prices caused losses on the net forward power purchase contracts.

The $1.5 billion decrease in Power s *cost of sales* is primarily due to a 20 percent decrease in power purchase volumes and an 18 percent decrease in average natural gas purchase prices.

The decrease in *selling, general and administrative expenses* is due primarily to increased gains from the sale of certain Enron receivables to a third party. Power recognized a $24.8 million gain in 2006 compared to a $9.7 million gain in 2005.

Other (income) expense net in 2006 includes a $12.7 million reduction of contingent obligations associated with our former distributive power generation business.

Other (income) expense net in 2005 includes:

An $82.2 million accrual for estimated litigation contingencies, primarily associated with agreements reached to substantially resolve exposure related to natural gas price and volume reporting issues (see Note 15 of Notes to Consolidated Financial Statements);

A $4.6 million accrual for a regulatory settlement;

A $23 million impairment of an equity investment (see Note 3 of Notes to Consolidated Financial Statements).

The decrease in *segment loss* is primarily due to favorable changes in *other (income) expense net* described above, partially offset by a decrease in gross margin.

2005 vs. 2004

The $164.8 million decrease in revenues includes a $32.9 million decrease in *realized revenues* and a $131.9 million decrease in *net forward unrealized mark-to -market gains (losses).*

The $32.9 million decrease in *realized revenues* is primarily due to the absence in 2005 of $471 million in crude and refined products realized revenues, partially offset by a $444 million increase in power and natural gas realized revenues. The absence of crude and refined products revenues is due to the sale of the refined products business in

2004. Power and natural gas realized revenues increased primarily due to a 33 percent increase in average natural gas sales prices and a 17 percent increase in average power sales prices. Hurricane Katrina, among other factors, contributed to the increase in prices. A 29 percent decrease in power sales volumes partially offsets the increase in prices. Power sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated and because of mild weather in California, which resulted in lower demand.

The $131.9 million decrease in *net forward unrealized mark-to-market gains (losses)* is primarily due to a $165 million decrease associated with power and gas derivative contracts, partially offset by the absence in 2005 of a $38 million unrealized loss on the interest rate portfolio in 2004.

The decrease in power and gas unrealized mark-to-market gains primarily results from the impact of cash flow hedge accounting, which was prospectively applied to certain of Power s derivative contracts beginning October 1, 2004. Net unrealized gains of $711 million related to the effective portion of the hedges are reported in *accumulated other comprehensive loss* in 2005 compared to $15 million in 2004. If Power had not applied cash flow hedge accounting in 2005, we would have reported the $711 million in *revenues* instead of in *accumulated other comprehensive loss.* Also in 2005, Power recognized losses of $6.8 million representing a correction of unrealized losses associated with a prior year. Our management concluded that the effects of this correction are not material to prior periods, 2005 results, or our trend of earnings. Partially offsetting these decreases is the effect of a greater increase in forward power prices on a greater volume of power purchase contracts in 2005 compared to 2004, resulting in increased unrealized mark-to-market gains on net power derivatives that are not accounted for as cash flow hedges.

The absence in 2005 of the unrealized loss on the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth quarter 2004. A decrease in forward interest rates caused unrealized losses in the interest rate portfolio in 2004.

The $77 million increase in Power s *cost of sales* is primarily due to an increase in power and natural gas costs of $563 million, partially offset by a decrease in crude and refined products costs of $486 million. Power and natural gas costs increased primarily due to a 32 percent increase in average power purchase prices and a 44 percent increase in average natural gas purchase prices, partially offset by a 29 percent decrease in power purchase volumes. Hurricane Katrina, among other factors, contributed to the increase in prices. Costs in 2005 include approximately $8 million in purchases due to an outage at an electric generating facility that Power has access to via a fuel conversion service agreement. A 2004 reduction to certain contingent loss accruals of $10.4 million associated with power marketing activities in California during 2000 and 2001 also contributes to the increase in costs. Costs in 2004 include $486 million of crude and refined products costs, which are absent in 2005 due to the sale of the refined products business in 2004. Costs in 2004 also reflect a $13 million payment made to terminate a nonderivative power sales contract.

Selling, general and administrative expenses decreased primarily due to decreased employee incentive compensation and decreased costs for outside services. A $9.7 million reduction of allowance for bad debts resulting from the sale of certain receivables to a third party also contributed to the decrease in *SG&A expenses. SG&A expenses* in 2004 include a $6.3 million reduction of allowance for bad debts resulting from a 2004 settlement with certain California utilities.

Other (income) expense net in 2004 includes $6.1 million in fees paid related to the sale of certain receivables to a third party.

Although increased gas prices favorably impacted the fair value of Power s derivative natural gas hedges, the $333.4 million change from a *segment profit* to a *segment loss* is primarily due to the impact of cash flow hedge accounting. Additionally, plant outages and depressed margin spreads between the cost of gas and sales price of electricity contributed to lower *segment profit.* Accruals in 2005 for litigation contingencies and an impairment of an equity investment also contributed to the change in *segment profit (loss).* Partially offsetting the decrease in *segment profit* is the absence in 2005 of unrealized and realized losses from the interest rate portfolio, which was liquidated in the fourth quarter of 2004.

Other

Overview of 2006

While we continue to have an equity ownership interest in Longhorn, the management of Longhorn completed an asset sale of the pipeline during the third quarter of 2006. As a result, we received full payment of the $10 million secured bridge loan that we provided Longhorn during 2005. The carrying value of our equity investment in Longhorn is zero as of December 31, 2006.

We continue to receive payments associated with the 2005 transfer of the Longhorn operating agreement to a third party. These payments totaled approximately $3.3 million for the year ended December 31, 2006. Any ongoing payments received or through monetization of the contract will be recognized as income when received. These ongoing payments were not impacted by the sale of the pipeline.

Year-Over-Year Operating Results

	Years Ended December 31, 2006	2005	2004
		(Millions)	
Segment revenues	$ 26.5	$ 27.2	$ 32.8
Segment profit (loss)	$ 1.9	$ (105.0)	$ (41.6)

2006 vs. 2005

Other *segment profit* for 2006 includes $3.3 million in payments received related to the 2005 transfer of the Longhorn operating agreement.

Other *segment loss* for 2005 includes $87.2 million of impairment charges, of which $38.1 million was recorded during the fourth quarter, related to our investment in Longhorn. In a related matter, we wrote off $4 million of capitalized project costs associated with Longhorn. We also recorded $23.7 million of equity losses associated with our investment in Longhorn. Partially offsetting these charges and losses was a $9 million fourth quarter gain on the sale of land.

2005 vs. 2004

Other *segment loss* for 2005 includes various items which are discussed above.

Other *segment loss* for 2004 includes $11.8 million of accrued environmental remediation expense associated with the Augusta refinery. Also included in Other *segment loss* is $10.8 million of impairment charges related to our investment in Longhorn, $9.8 million of equity losses associated with our investment in Longhorn, and $6.5 million of net unreimbursed advisory fees related to the recapitalization of Longhorn.

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of December 31, 2006. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

Net Assets (Liabilities) Trading (Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value

$3	$	$	$	$	$	3

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Power s forecasted purchases of gas, its purchases and sales of power related to its long-term structured contracts and owned generation, and Exploration & Production s forecasted sales of natural gas production. Certain of Power s other derivatives have not been designated as or do not qualify as SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) cash flow hedges. The chart below reflects the fair value of derivatives held for nontrading purposes as of December 31, 2006, for the Power and Exploration & Production businesses. Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $360 million as of December 31, 2006, which includes the existing fair value of the derivatives at the time of their designation as SFAS 133 cash flow hedges.

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Net Assets (Liabilities) Nontrading (Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$94	$ 227	$ 88	$ 24	$	$ 433

Methods of Estimating Fair Value

Most of the derivatives we hold settle in active periods and markets in which quoted market prices are available. These include futures contracts, option contracts, swap agreements and physical commodity purchases and sales in the commodity markets in which we transact. While an active market may not exist for the entire period, quoted prices can generally be obtained for natural gas through 2012 and power through 2011.

These prices reflect current economic and regulatory conditions and may change because of market conditions. The availability of quoted market prices in active markets varies between periods and commodities based upon changes in market conditions. The ability to obtain quoted market prices also varies greatly from region to region. The time periods noted above are an estimation of aggregate availability of quoted prices. An immaterial portion of our total net derivative value of $436 million relates to periods in which active quotes cannot be obtained. We estimate energy commodity prices in these illiquid periods by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis. Modeling and other valuation techniques, however, are not used significantly in determining the fair value of our derivatives.

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor s and Moody s Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At December 31, 2006, we held collateral support, including letters of credit, of $695 million.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2006 and 2005, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of December 31, 2006, is summarized below.

Investment

Counterparty Type	**Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 248.0	$ 249.9
Energy marketers and traders	412.7	1,784.3
Financial institutions	2,219.4	2,219.4
Other	23.3	29.8
	$ 2,903.4	4,283.4
Credit reserves		(20.3)
Gross credit exposure from derivatives		$ 4,263.1

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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, 2006, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 120.4	$ 120.5
Energy marketers and traders	209.0	455.4
Financial institutions	325.5	325.5
Other	20.4	20.4
	$ 675.3	921.8
Credit reserves		(20.3)
Net credit exposure from derivatives		$ 901.5

(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum Standard & Poor s rating of BBB- or Moody s Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

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. Power s value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Management s Discussion and Analysis of Financial Condition

Outlook

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. In 2007, we expect to maintain liquidity from cash and cash equivalents and unused revolving credit facilities of at least $1 billion. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements through cash flow from operations, which is currently estimated to be between $2 billion and $2.3 billion in 2007, proceeds from debt issuances and sales of units of Williams Partners L.P., as well as cash and cash equivalents on hand as needed.

We enter 2007 positioned for growth through disciplined investments in our natural gas businesses. Examples of this planned growth include:

Exploration & Production will continue to maintain its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth. During 2006, all ten state-of-the-art FlexRig4® drilling rigs were placed in service in the Piceance basin pursuant to our March 2005 contract with Helmerich & Payne. Each rig is leased for three years.

Gas Pipeline will continue to expand its system to meet the demand of growth markets.

Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.2 billion to $2.4 billion in 2007. As a result of increasing our development drilling program, $1.3 billion to $1.4 billion of the total estimated 2007 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2007 is approximately $215 million to $270 million for maintenance-related projects at Gas Pipeline, including pipeline replacement and Clean Air Act compliance. Commitments for construction and acquisition of property, plant and equipment are approximately $406 million at December 31, 2006.

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 due to commodity pricing volatility. To mitigate this exposure, Exploration & Production has economically hedged the price of natural gas for approximately 172 MMcfe per day of its expected 2007 production. In addition, Exploration & Production has collar agreements for each month of 2007 which hedge approximately 270 MMcfe per day of expected 2007 production. Power has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of December 31, 2006, we estimate our exposure to additional margin requirements through 2007 to be no more than $521 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 15 of Notes to Consolidated Financial Statements).

In August 2006, the Pension Protection Act of 2006 was signed into law. The Act makes significant changes to the requirements for employer-sponsored retirement plans, including revisions affecting the funding of defined benefit pension plans beginning in 2008. We are assessing the impact of the legislation on our future funding requirements, but do not expect a significant increase in required contributions over current levels, assuming long-term rates of return on assets and current discount rates do not experience a significant decline.

Overview

In November 2005, we initiated an offer to induce conversion of up to $300 million of the 5.5 percent junior subordinated convertible debentures into our common stock. The conversion was executed in January 2006 and approximately $220.2 million of the debentures were exchanged for common stock. We paid $25.8 million in premiums that are included in *early debt retirement costs* in the Consolidated Statement of Income. See Note 12 of Notes to Consolidated Financial Statements for further information.

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement to fund general corporate expenses and capital expenditures. In October 2006, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In May 2006, we replaced our $1.275 billion secured revolving credit facility with a $1.5 billion unsecured revolving credit facility. The new facility contains similar terms and financial covenants as the secured facility, but contains certain additional restrictions. (See Note 11 of Notes to Consolidated Financial Statements.)

In June 2006, Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement to fund general corporate expenses and capital expenditures. In October 2006, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In June 2006, we reached an agreement-in-principle to settle class-action securities litigation filed on behalf of purchasers of our securities between July 24, 2000 and July 22, 2002, for a total payment of $290 million to plaintiffs. On February 9, 2007, the court gave its final approval of the settlement. We recorded a pre-tax charge for approximately $161 million in second quarter 2006. Our portion of the total payment was $145 million.

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On June 1, 2006, the FERC entered its final order (FERC Final Order) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank litigation. The Quality Bank Administrator will determine and invoice for amounts due based on the FERC Final Order, subject to the final disposition of the FERC Final Order appeals. We estimate that our net obligation could be as much as $116 million. (See Note 15 of Notes to Consolidated Financial Statements.)

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. 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 and an equity offering of approximately $225 million in net proceeds. In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

Exploration & Production has recently 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 and on natural gas reserves value.

Credit ratings

On May 4, 2006, Standard & Poor s raised our senior unsecured debt rating from a B+ to a BB- with a positive 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 it s ratings with a + or a sign to show the obligor s relative standing within a major rating category.

On June 7, 2006, Moody s Investors Service raised our senior unsecured debt rating from a B1 to a Ba2 with a stable ratings outlook. 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. A Ba rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. 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.

On May 15, 2006, Fitch Ratings raised our senior unsecured rating from BB to BB+ with a stable ratings outlook. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. A BB rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a + or a sign to show the obligor s relative standing within a major rating category.

Our goal is to attain investment grade ratings at some point in the future.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, and 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 are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

	Year Ended December 31, 2006 (Millions)
Cash and cash equivalents*	$ 2,268.6
Auction rate securities and other liquid securities	103.2
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	304.9
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,471.2
	$ 4,147.9

* *Cash and cash equivalents* includes $128.7 million of funds received from third parties as collateral. The obligation for these amounts is reported as *customer margin deposits payable* on the Consolidated Balance Sheet. Also included is $347 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** This facility is guaranteed by Williams Gas Pipeline Company, L.L.C. Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. Williams Partners L.P. has access to $75 million, to the extent not utilized by us, that we guarantee.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. The ability of Northwest Pipeline to utilize their registration statement to issue debt securities is restricted by certain covenants of its debt agreements. If the credit rating of Northwest Pipeline or Transco is below investment grade, they can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed. This registration statement, filed May 19, 2006, replaces our previously filed shelf registration.

Sources (Uses) of Cash

	Years Ended December 31,		
	2006	2005	2004
		(Millions)	
Net cash provided (used) by:			
Operating activities	$ 1,889.6	$ 1,449.9	$ 1,487.9

Financing activities	1,103.2	36.5	(3,505.5)
Investing activities	(2,321.4)	(819.2)	629.4
Increase (decrease) in cash and cash equivalents	$ 671.4	$ 667.2	$ (1,388.2)

Operating Activities

Our *net cash provided by operating activities* in 2006 increased from 2005 due largely to higher operating income at Midstream, partially offset by a $145 million securities litigation settlement payment in fourth quarter 2006.

Our 2005 *net cash provided by operating activities* decreased slightly from 2004. A primary driver in *net cash provided by operating activities* is *income from continuing operations,* which increased primarily as a result of higher gas production volumes and net average realized prices for production sold. Also contributing to the increase in income from continuing operations is the reduction in interest expense due to lower average borrowing levels.

Cash payments for interest decreased $224 million from 2004. In addition to the changes in results of operations, net cash inflows from margin deposits and customer margin deposits payable decreased significantly from 2004. In 2004, our Power subsidiary issued a significant number of letters of credit to replace its cash margin deposits. As the letters of credit were issued, the counterparties returned our cash margin deposits to us. Due to fewer letters of credit being issued to replace cash margin deposits in 2005, we have fewer receipts of margin deposits than in 2004.

Other, including changes in noncurrent assets and liabilities, includes contributions to our tax-qualified pension plans of $42.1 million in 2006, $52.1 million in 2005 and $136.8 million in 2004. It is our policy to make annual contributions to our tax-qualified pension plans in an amount at least equal to the greater of the actuarially computed annual normal cost plus any unfunded actuarial accrued liability, amortized over approximately five years, or the minimum required contribution under existing laws. Additional amounts may be contributed to increase the funded status of the plans. In an effort to strengthen our funded status and take advantage of strong cash flows, we contributed approximately $26.5 million, $41.1 million and $98.9 million more than our funding policy required in 2006, 2005 and 2004, respectively.

Financing Activities

During the first quarter of 2006, we paid $25.8 million in premiums for early debt retirement costs relating to the debt conversion previously discussed.

See Overview, within this section, for a discussion of 2006 debt issuances, debt retirement, and additional financing by Williams Partners L.P.

During January 2005, we retired $200 million of 6.125 percent notes issued by Transco, which matured January 15, 2005. In the first quarter of 2005, we received approximately $273 million in *proceeds from the issuance of common stock* purchased under the FELINE PACS equity forward contracts. During August 2005, we completed an initial public offering of approximately 40 percent of our interest in Williams Partners L.P. resulting in net proceeds of $111 million.

During 2004, we repaid long-term debt through tender offers and early retirements. We also reduced our debt through our FELINE PACS exchange. This noncash exchange resulted in payments of fees and expenses reported as *premiums paid on tender offer, early debt retirements and FELINE PACS exchange.*

Quarterly dividends paid on common stock increased from 7.5 cents to 9 cents per common share during the second quarter of 2006 and totaled $206.6 million for year ended December 31, 2006. For the fourth quarter of 2005, dividends paid on common stock were 7.5 cents per share and totaled $143 million for the year ended December 31, 2005.

Investing Activities

During 2006, capital expenditures totaled $2,509.2 million and were primarily related to Exploration & Production s increased drilling activity, mostly in the Piceance basin, and Northwest Pipeline s capacity replacement project.

During 2006, we purchased $386.3 million and received $414.1 million from the sale of auction rate securities. These instruments are utilized as a component of our overall cash management program.

In January 2005, Northwest Pipeline received an $87.9 million contract termination payment, representing reimbursement of the net book value of the related assets.

In January 2005, we received approximately $54.7 million proceeds from the sale of our note with Williams Communications Group, our previously owned subsidiary (WilTel).

During 2005, we received $310.5 million in proceeds from the Gulfstream recapitalization.

In 2004, we sold all of our restricted investments resulting in proceeds of $851.4 million. When our $800 million revolving and letter of credit facility that required 105 percent cash collateral was replaced with a new revolving credit facility in January 2005, we were no longer required to hold the restricted investments.

In 2004, we had numerous asset sales resulting in proceeds in 2004 of $877.8 million.

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

In January 2005, we terminated our two unsecured revolving and letter of credit facilities totaling $500 million and replaced them with two new facilities that contain similar terms but fewer restrictions. In September 2005, we also entered into two new revolving and letter of credit facilities that have a similar structure. (See Note 11 of Notes to Consolidated Financial Statements.)

We have provided a guarantee for obligations of Williams Partners L.P. under the $1.5 billion unsecured revolving and letter of credit facility.

We have various other guarantees and commitments which are disclosed in Notes 3, 10, 11, 14, and 15 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 by period.

	2007	2008-2009	2010-2011	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 391	$ 291	$ 1,385	$ 5,974	$ 8,041
Interest	606	1,147	1,083	5,713	8,549
Capital leases	2	3			5
Operating leases(1)	227	433	366	1,121	2,147
Purchase obligations:					
Fuel conversion and other service contracts(2)(5)	249	505	495	2,377	3,626
Other(5)(6)	877	1,134	1,144	2,943(4)	6,098
Other long-term liabilities, including current portion:					
Physical and financial derivatives(3)(5)	628	392	204	304	1,528
Other(7)	72	31	16		119
Total	$ 3,052	$ 3,936	$ 4,693	$ 18,432	$ 30,113

(1) Excludes sublease income of $1.2 billion consisting of $331 million in 2007, $564 million in 2008-2009, and $258 million in 2010-2011. Includes a Power tolling agreement that is accounted for as an operating lease.

(2) Power has entered into certain contracts giving us the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the

continental United States. Certain of Power s tolling agreements could be considered leases pursuant to the guidance in EITF Issue 01-8, Determining Whether an Arrangement Contains a Lease, if in the future the agreements are modified for any reason. If deemed to be a capital lease, the net present value of the fixed demand payments would be reported on the Consolidated Balance Sheet consistent with other capital lease obligations, and as an asset in *property, plant and equipment net.* See Note 1 of Notes to the Consolidated Financial Statements for further information.

(3) The obligations for physical and financial derivatives are based on market information as of December 31, 2006. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

(4) Includes one year of annual payments totaling $2 million for contracts with indefinite termination dates.

(5) Expected offsetting cash inflows of $7.2 billion at December 31, 2006, 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.

(6) Includes $4.5 billion of natural gas purchase obligations at market prices at our Exploration & Production segment. The purchased natural gas can be sold at market prices.

(7) 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 $58 million in 2006 and $73 million in 2005. In 2007, we expect to contribute approximately $57 million to these plans (see Note 7 of Notes to Consolidated Financial Statements), including $40 million to our tax-qualified pension plans. There were no minimum funding requirements to our tax-qualified pension plans in 2006 or 2005, and we do not expect any minimum funding requirements in 2007. We anticipate that future contributions will not vary significantly from recent historical contributions, assuming actual results do not differ significantly from estimated results for assumptions such as discount rates, returns on plan assets, retirement rates, mortality and other significant assumptions, and assuming no further changes in current and prospective legislation and regulations. Based on these anticipated levels of future contributions, we do not expect to trigger any minimum funding requirements in the future.

Effects of Inflation

Our operations in recent years have benefited from relatively low inflation rates. Approximately 46 percent of our gross property, plant and equipment is at Gas Pipeline and the remainder is at other operating units. 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, refined product, natural gas, natural gas liquids and power prices are particularly sensitive to OPEC production levels and/or the market perceptions concerning the supply and demand balance in the near future. However, our exposure to these price changes is reduced through the use of hedging instruments.

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 15 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 $52 million, all of which are recorded as liabilities on our balance sheet at December 31, 2006. We will seek recovery of approximately $11 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2006, we paid approximately $12 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $17 million in 2007 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, 2006, 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.

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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 impose additional controls. Capital expenditures necessary to install emission control devices on our Transco gas pipeline system to comply with rules were approximately $41 million in 2006 and are estimated to be between $35 million and $40 million through 2010. 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.

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Item 7A. ***Qualitative and Quantitative 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, 2006 and 2005. 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 the prices of similar securities with similar terms and credit ratings.

	2007	2008	2009	2010	2011	Thereafter(1)	Total	Fair Value December 31, 2006
				(Dollars in millions)				
Long-term debt, including current portion(4):								
Fixed rate	$ 381	$ 153	$ 41	$ 205	$ 1,161	$ 5,922	$ 7,863	$ 8,343
Interest rate	7.7%	7.7%	7.7%	7.5%	7.6%	7.8%		
Variable rate	$ 10	$ 85	$ 12	$ 12	$ 7	$ 23	$ 149	$ 137
Interest rate(2)								

	2006	2007	2008	2009	2010	Thereafter(1)	Total	Fair Value December 31, 2005
				(Dollars in millions)				
Long-term debt, including current portion(4):								
Fixed rate	$ 104	$ 381	$ 153	$ 41	$ 205	$ 6,179	$ 7,063	$ 7,952
Interest rate	7.7%	7.7%	7.8%	7.8%	7.8%	7.8%		
Variable rate	$ 15	$ 15	$ 563	$ 12	$ 12	$ 30	$ 647	$ 647
Interest rate(3)								

(1) Including unamortized discount and premium.

(2) The weighted-average interest rate for 2006 is LIBOR plus 1 percent.

(3) The weighted-average interest rate for 2005 was LIBOR plus 2 percent.

(4) Excludes capital leases.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, electricity, and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations, including correlations between natural gas and power prices. 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

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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 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. Our value at risk for contracts held for trading purposes was approximately $1 million at December 31, 2006, and $4 million at December 31, 2005. During the year ended December 31, 2006, our value at risk for these contracts ranged from a high of $4 million to a low of $1 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
Power	Natural gas purchases and sales Electricity purchases and sales

The value at risk for derivative contracts held for nontrading purposes was $12 million at December 31, 2006, and $28 million at December 31, 2005. During the year ended December 31, 2006, our value at risk for these contracts ranged from a high of $25 million to a low of $12 million. Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any change in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

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 $42 million at December 31, 2006, and $45 million at December 31, 2005. 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. If a 20 percent change occurred in the value of the underlying currencies of these investments against the U.S. dollar, the fair value at December 31, 2006, could change by approximately $8.3 million assuming a direct correlation between the currency fluctuation and the value of the investments.

Net assets of consolidated foreign operations whose functional currency is the local currency are located primarily in Canada and approximate 6 percent of our net assets at December 31, 2006 and 2005. 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 re-measuring 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 could have changed *stockholders equity* by approximately $68 million at December 31, 2006.

Item 8. *Financial Statements and Supplementary Data*

MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Williams 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) and for the assessment of the effectiveness of internal control over financial reporting. Our internal control system was 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. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Our management assessed the effectiveness of Williams internal control over financial reporting as of December 31, 2006. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based on our assessment we believe that, as of December 31, 2006, Williams internal control over financial reporting is effective based on those criteria.

Ernst & Young, LLP, our independent registered public accounting firm, has issued an audit report on our assessment of the company s internal control over financial reporting. A copy of this report is included in this Annual Report on Form 10-K.

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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 management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that The Williams Companies, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that The Williams Companies, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, The Williams Companies, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006 of The Williams Companies, Inc. and our report dated February 22, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2007

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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, 2006 and 2005, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, 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 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), *Share-Based Payment* and as explained in Note 7 to the consolidated financial statements, effective December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.* Also, as explained in Note 9 to the consolidated financial statements, effective December 31, 2005, the Company adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of The Williams Companies, Inc. s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 22, 2007

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF INCOME

	Years Ended December 31,		
	2006	2005	2004
	(Millions, except per-share amounts)		
Revenues:			
Exploration & Production	$ 1,487.6	$ 1,269.1	$ 777.6
Gas Pipeline	1,347.7	1,412.8	1,362.3
Midstream Gas & Liquids	4,124.7	3,232.7	2,882.6
Power	7,462.4	9,093.9	9,272.4
Other	26.5	27.2	32.8
Intercompany eliminations	(2,636.0)	(2,452.1)	(1,866.4)
Total revenues	11,812.9	12,583.6	12,461.3
Segment costs and expenses:			
Costs and operating expenses	9,973.6	10,871.0	10,751.7
Selling, general and administrative expenses	449.2	325.4	355.5
Other (income) expense net	20.7	61.2	(51.6)
Total segment costs and expenses	10,443.5	11,257.6	11,055.6
General corporate expenses	132.1	145.5	119.8
Securities litigation settlement and related costs	167.3	9.4	
Operating income (loss):			
Exploration & Production	529.7	568.4	223.9
Gas Pipeline	430.3	542.2	557.6
Midstream Gas & Liquids	631.3	446.6	552.2
Power	(223.8)	(236.8)	86.5
Other	1.9	5.6	(14.5)
General corporate expenses	(132.1)	(145.5)	(119.8)
Securities litigation settlement and related costs	(167.3)	(9.4)	
Total operating income	1,070.0	1,171.1	1,285.9
Interest accrued	(676.1)	(671.7)	(834.4)
Interest capitalized	17.2	7.2	6.7
Investing income	173.0	23.7	48.0
Early debt retirement costs	(31.4)	(0.4)	(282.1)
Minority interest in income of consolidated subsidiaries	(40.0)	(25.7)	(21.4)
Other income net	26.4	27.1	21.8
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	539.1	531.3	224.5

Provision for income taxes		206.3		213.9		131.3
Income from continuing operations		332.8		317.4		93.2
Income (loss) from discontinued operations		(24.3)		(2.1)		70.5
Income before cumulative effect of change in accounting principle		308.5		315.3		163.7
Cumulative effect of change in accounting principle				(1.7)		
Net income	$	308.5	$	313.6	$	163.7
Basic earnings (loss) per common share:						
Income from continuing operations	$	.56	$	.55	$	.18
Income (loss) from discontinued operations		(.04)				.13
Income before cumulative effect of change in accounting principle		.52		.55		.31
Cumulative effect of change in accounting principle						
Net income	$	.52	$	.55	$	.31
Weighted-average shares (thousands)		595,053		570,420		529,188
Diluted earnings (loss) per common share:						
Income from continuing operations	$	.55	$	.53	$	.18
Income (loss) from discontinued operations		(.04)				.13
Income before cumulative effect of change in accounting principle		.51		.53		.31
Cumulative effect of change in accounting principle						
Net income	$	.51	$	.53	$	.31
Weighted-average shares (thousands)		608,627		605,847		535,611

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2006	December 31, 2005
	(Dollars in millions, except per-share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,268.6	$ 1,597.2
Restricted cash	91.6	92.9
Accounts and notes receivable (net of allowance of $15.9 million in 2006 and $86.6 million in 2005)	1,212.9	1,613.8
Inventories	241.4	272.6
Derivative assets	1,878.2	5,299.7
Margin deposits	59.3	349.2
Deferred income taxes	337.2	241.0
Other current assets and deferred charges	232.8	230.9
Total current assets	6,322.0	9,697.3
Restricted cash	34.5	36.5
Investments	866.0	887.8
Property, plant and equipment net	14,180.7	12,409.2
Derivative assets	2,384.9	4,656.9
Goodwill	1,011.4	1,014.5
Other assets and deferred charges	602.9	740.4
Total assets	$ 25,402.4	$ 29,442.6
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,148.5	$ 1,360.6
Accrued liabilities	1,241.4	1,123.1
Customer margin deposits payable	128.7	320.7
Derivative liabilities	1,782.9	5,523.2
Long-term debt due within one year	392.1	122.6
Total current liabilities	4,693.6	8,450.2
Long-term debt	7,622.0	7,590.5
Deferred income taxes	2,879.9	2,508.9
Derivative liabilities	2,043.8	4,331.1
Other liabilities and deferred income	1,009.1	920.3
Contingent liabilities and commitments (Note 15)		
Minority interests in consolidated subsidiaries	1,080.8	214.1
Stockholders equity:		

Common stock (960 million shares authorized at $1 par value; 602.8 million shares issued at December 31, 2006, and 579.1 million shares issued at December 31,2005)	602.8	579.1
Capital in excess of par value	6,605.7	6,327.8
Accumulated deficit	(1,034.0)	(1,135.9)
Accumulated other comprehensive loss	(60.1)	(297.8)
Other		(4.5)
	6,114.4	5,468.7
Less treasury stock, at cost (5.7 million shares of common stock in 2006 and 2005)	(41.2)	(41.2)
Total stockholders equity	6,073.2	5,427.5
Total liabilities and stockholders equity	$ 25,402.4	$ 29,442.6

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY

	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Loss	Other	Treasury Stock	Total
	(Dollars in millions)						
Balance, December 31, 2003	$ 524.0	$ 5,195.1	$ (1,426.8)	$ (121.0)	$ (28.0)	$ (41.2)	$ 4,102.1
Comprehensive income:							
Net income 2004			163.7				163.7
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments				(142.7)			(142.7)
Net unrealized appreciation on marketable equity securities, net of reclassification adjustments				1.9			1.9
Foreign currency translation adjustments				15.8			15.8
Minimum pension liability adjustment				1.8			1.8
Total other comprehensive loss							(123.2)
Total comprehensive income							40.5
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange	33.1	782.9					816.0
Cash dividends Common stock ($.08 per share)			(43.4)				(43.4)
Allowance for and repayment of stockholders notes					6.1		6.1
Stock award transactions, including tax benefit	6.7	27.9					34.6
Balance, December 31, 2004	563.8	6,005.9	(1,306.5)	(244.2)	(21.9)	(41.2)	4,955.9

Comprehensive income:							
Net income 2005			313.6				313.6
Other comprehensive loss:							
Net unrealized losses on cash flow hedges, net of reclassification adjustments				(65.4)			(65.4)
Foreign currency translation adjustments				11.4			11.4
Minimum pension liability adjustment				.4			.4
Total other comprehensive loss							(53.6)
Total comprehensive income							260.0
Issuance of common stock and settlement of forward contracts as a result of FELINE PACS exchange	10.9	261.9					272.8
Cash dividends Common stock ($.25 per share)			(143.0)				(143.0)
Allowance for and repayment of stockholders notes					17.4		17.4
Stock award transactions, including tax benefit	4.4	60.0					64.4
Balance, December 31, 2005	579.1	6,327.8	(1,135.9)	(297.8)	(4.5)	(41.2)	5,427.5
Comprehensive income:							
Net income 2006			308.5				308.5
Other comprehensive income:							
Net unrealized gains on cash flow hedges, net of reclassification adjustments				394.2			394.2
Foreign currency translation adjustments				(4.7)			(4.7)
Minimum pension liability adjustment				(.9)			(.9)
Total other comprehensive income							388.6
Total comprehensive income							697.1
Adjustment to initially apply SFAS No. 158, net of tax:							
Pension benefits:							
Prior service cost				(3.5)			(3.5)

Net actuarial loss				(150.7)			(150.7)
Minimum pension liability				5.3			5.3
Other postretirement benefits:							
Prior service cost				(4.1)			(4.1)
Net actuarial gain				2.1			2.1
Issuance of common stock from 5.5% debentures conversion (Note 12)	20.2	193.2					213.4
Cash dividends Common stock ($.35 per share)			(206.6)				(206.6)
Repayment of stockholders notes					4.5		4.5
Stock award transactions, including tax benefit	3.5	84.7					88.2
Balance, December 31, 2006	$ 602.8	$ 6,605.7	$ (1,034.0)	$ (60.1)	$	$ (41.2)	$ 6,073.2

See accompanying notes.

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THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	Years Ended December 31, 2006	2005	2004
		(Millions)	
OPERATING ACTIVITIES:			
Net income	$ 308.5	$ 313.6	$ 163.7
Adjustments to reconcile to net cash provided by operations:			
(Income) loss from discontinued operations	24.3	2.1	(70.5)
Cumulative effect of change in accounting principle		1.7	
Depreciation, depletion and amortization	865.5	740.0	668.5
Provision (benefit) for deferred income taxes	169.2	(45.3)	123.0
Provision for loss on investments, property and other assets	25.5	118.7	86.7
Net gain on dispositions of assets	(22.5)	(58.3)	(18.1)
Early debt retirement costs	31.4	.4	282.1
Minority interest in income of consolidated subsidiaries	40.0	25.7	21.4
Amortization of stock-based awards	43.9	12.7	9.5
Cash provided (used) by changes in current assets and liabilities:			
Restricted cash	4.2	(14.0)	(14.1)
Accounts and notes receivable	378.1	(240.9)	234.6
Inventories	31.3	(9.7)	(18.3)
Margin deposits and customer margin deposits payable	97.9	85.5	414.1
Other current assets and deferred charges	(34.2)	5.9	112.8
Accounts payable	(183.9)	232.5	(118.5)
Accrued liabilities	(147.9)	22.9	(218.9)
Changes in current and noncurrent derivative assets and liabilities	303.2	173.9	(160.4)
Changes in noncurrent restricted cash			86.5
Other, including changes in noncurrent assets and liabilities	(51.5)	82.5	(112.0)
Net cash provided by operating activities of continuing operations	1,883.0	1,449.9	1,472.1
Net cash provided by operating activities of discontinued operations	6.6		15.8
Net cash provided by operating activities	1,889.6	1,449.9	1,487.9
FINANCING ACTIVITIES:			
Proceeds from long-term debt	1,299.4		75.0
Payments of long-term debt	(776.7)	(251.2)	(3,263.2)
Proceeds from issuance of common stock	34.3	309.9	20.6
Proceeds from sale of limited partner units of consolidated partnership	863.4	111.0	
Tax benefit of stock-based awards	15.5		
Dividends paid	(206.6)	(143.0)	(43.4)
Payments for debt issuance costs and amendment fees	(37.0)	(29.6)	(26.0)
Premiums paid on tender offer, early debt retirements and FELINE PACS exchange	(25.8)	(.4)	(246.9)
Dividends and distributions paid to minority interests	(36.2)	(20.7)	(5.9)

Changes in restricted cash	(.6)	(2.7)	21.7
Changes in cash overdrafts	(25.3)	63.2	(21.4)
Other net	(1.2)		(14.8)
Net cash provided (used) by financing activities of continuing operations	1,103.2	36.5	(3,504.3)
Net cash used by financing activities of discontinued operations			(1.2)
Net cash provided (used) by financing activities	1,103.2	36.5	(3,505.5)
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(2,509.2)	(1,299.0)	(787.4)
Net proceeds from dispositions	22.9	47.3	12.0
Proceeds from contract termination payment	3.3	87.9	
Changes in accounts payable and accrued liabilities	104.7	65.1	
Purchases of investments/advances to affiliates	(48.9)	(116.1)	(2.1)
Purchases of auction rate securities	(386.3)	(224.0)	
Purchases of restricted investments			(471.8)
Proceeds from sales of businesses		31.4	877.8
Proceeds from sales of auction rate securities	414.1	137.9	
Proceeds from sale of restricted investments			851.4
Proceeds from dispositions of investments and other assets	62.3	64.2	94.1
Proceeds received on sale of note from WilTel		54.7	
Payments received on notes receivable from WilTel			69.1
Proceeds from Gulfstream recapitalization		310.5	
Other net	15.7	20.9	(12.9)
Net cash provided (used) by investing activities of continuing operations	(2,321.4)	(819.2)	630.2
Net cash used by investing activities of discontinued operations			(.8)
Net cash provided (used) by investing activities	(2,321.4)	(819.2)	629.4
Increase (decrease) in cash and cash equivalents	671.4	667.2	(1,388.2)
Cash and cash equivalents at beginning of year	1,597.2	930.0	2,318.2
Cash and cash equivalents at end of year	$ 2,268.6	$ 1,597.2	$ 930.0

See accompanying notes.

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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 Power.

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. The Gas Pipeline operating segments have been aggregated for reporting purposes and include Northwest Pipeline Corporation (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 Corporation (Transco), which extends from the Gulf of Mexico region to the northeastern United States. In addition, we own a 50 percent interest in 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.

Power is an energy services provider that buys, sells, stores, and transports energy and energy-related commodities, primarily power and natural gas, on a wholesale level. Power focuses on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio, and providing commodity marketing and supply services that support our natural gas businesses.

Basis of Presentation

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

Certain amounts have been reclassified to conform to the current classifications.

In February 2005, we formed Williams Partners L.P., a limited partnership engaged in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. We currently own approximately 22.5 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us. 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, Williams Partners L.P. is consolidated within our Midstream segment.

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.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Use of estimates

Management makes 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;
- Environmental remediation obligations;
- Hedge accounting correlations and probability;
- 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

Cash and cash equivalents includes demand and time deposits, certificates of deposit, and other marketable securities with maturities of three months or less when acquired.

Restricted cash

Restricted cash within *current assets* consists primarily of collateral required by certain loan agreements for our Venezuelan operations, escrow accounts established to fund payments required by Power s California settlement (see Note 15), and an escrow account used to collect and manage margin dollars. *Restricted cash* within noncurrent assets 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 vehicle.

Auction rate securities

Auction rate securities are instruments with long-term underlying maturities, but for which an auction is conducted periodically, as specified, to reset the interest rate and allow investors to buy or sell the instruments. Because auctions generally occur more often than annually, and because we hold these investments in order to meet short-term liquidity needs, we classify auction rate securities as short-term and include them in *other current assets and deferred charges* on our Consolidated Balance Sheet. Consistent with our other securities that are classified as available-for-sale, 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*.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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. Depreciation rates used for major regulated gas plant facilities for all years presented, are as follows:

Category of Property	**Depreciation Rates**
Gathering facilities	0% - 3.80%
Storage facilities	1.05% - 2.50%
Onshore transmission facilities	2.35% - 7.25%
Offshore transmission facilities	0.85% - 1.50%

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. The estimated useful lives are as follows:

Category of Property	**Estimated Useful Lives (In years)**
Natural gas gathering and processing facilities	10 to 40
Power generation facilities	30
Transportation equipment	3 to 30
Building and improvements	5 to 45
Right of way	4 to 40
Office furnishings and computer software and hardware	3 to 20

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. Unproved properties are evaluated annually, or as conditions warrant, to determine any impairment in carrying value. *Depreciation, depletion and amortization* is provided under the units of production method on a field basis.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Proved properties, including developed and undeveloped, and costs associated with unproven reserves, are assessed for impairment using estimated future cash flows on a field basis. 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.

We record an asset and a liability 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, 2006, and 2005, at 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 2005 and 2004 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 undiscounted 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.

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 execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual contracts.

The accounting for changes in the fair value of a commodity derivative is governed by Statement of Financial Accounting Standard (SFAS) No. 133 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 have elected 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. Some contracts had a fair value at the date of the election and are reflected on the balance sheet at their fair value on the date of the election less the amount of that fair value realized during settlement periods subsequent to the election. For other contracts, we made the election at the inception of the contract and thus there is no recorded fair value.

We have also designated a hedging relationship for certain commodity derivatives. Prior to September 2004, Power s derivative contracts did not qualify for hedge accounting because of our stated intent to exit the Power business. In September 2004, we announced our decision to continue operating the Power business. As a result of that decision, Power s derivative contracts became eligible for hedge accounting. Power elected cash flow hedge accounting on a prospective basis beginning October 1, 2004, for certain qualifying derivative contracts.

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*.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Unrealized gains and losses on all derivatives that are not designated as hedges and for which we have not elected the normal purchases and normal sales exception;

The ineffective portion of unrealized gains and losses on derivatives that are designated as cash flow hedges;

Realized gains and losses on all derivatives that settle financially;

Realized gains and losses on derivatives held for trading purposes;

Realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, and which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we evaluated the indicators in EITF Issue No. 99-19 Reporting Revenue Gross as a Principal versus as an Agent, including whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Assessment of energy-related contracts for lease classification

EITF 01-8, Determining Whether an Arrangement Contains a Lease, became effective on July 1, 2003, and provides guidance for determining whether certain contracts such as transportation, transmission, storage, full requirements, and tolling agreements are executory service arrangements or leases pursuant to SFAS No. 13, Accounting for Leases. The consensus is applied prospectively to arrangements consummated or modified after July 1, 2003. Prior to July 1, 2003, we accounted for energy-related contracts as executory service arrangements and continue this accounting unless a contract is subsequently modified and evaluated to be a lease. For executory service arrangements, the monthly demand payments are expensed as incurred. Certain of Power s tolling agreements will likely be considered leases under the consensus if the tolling agreements are ever modified. One tolling agreement was modified in 2004 and is accounted for as an operating lease. For tolling agreements that are modified and deemed to be operating leases, the monthly demand payments are expensed as incurred. If the monthly demand payments are not incurred on a straight-line basis, expense is nevertheless recognized on a straight-line basis. If such tolling agreements are modified and deemed to be capital leases, the net present value of the demand payments would be reported on the Consolidated Balance Sheet as *long-term debt* and as an asset in *property, plant and equipment net*.

Gas Pipeline revenues

Revenues from the transportation of gas are recognized in the period the service is provided, and revenues for sales of products are recognized in the period of delivery. Gas Pipeline is subject to FERC regulations and, accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending rate cases. Gas Pipeline records estimates of rate refund liabilities considering Gas Pipeline 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Revenues, other than Gas Pipeline, Exploration & Production, and energy commodity risk management and trading activities

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. 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. 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, Accounting for the Impairment or Disposal of Long-Lived Assets, 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.

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 on major projects during construction. 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 unregulated companies are based on the average interest rate on debt. The benefit of interest capitalized on internally generated funds for regulated entities is reported in *other income net* below *operating income*.

Additionally, Exploration & Production capitalizes interest on those construction projects with construction periods of at least three months and a total project cost in excess of $1 million. Exploration & Production capitalizes interest on equity investments when the investee is undergoing construction in preparation for its planned principal operations.

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Employee stock-based awards

Prior to January 1, 2006, we accounted for stock-based awards to employees and nonmanagement directors (see Note 13) under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, as permitted by Financial Accounting Standards Board (FASB) Statement No. 123, Accounting for Stock-Based Compensation (SFAS No. 123). Compensation cost for stock options was not recognized in the Consolidated Statement of Income for the years prior to 2006 as all options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant. Prior to January 1, 2006, compensation cost was recognized for restricted stock units. Effective January 1, 2006, we adopted the fair value recognition provisions of FASB Statement No. 123(R), Share-Based Payment (SFAS No. 123(R)), using the modified-prospective method. Under this method, compensation cost recognized in 2006 includes: (1) compensation cost for all share-based payments granted through December 31, 2005, but for which the requisite service period had not been completed as of December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123, and (2) compensation cost for most share-based payments granted subsequent to December 31, 2005, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R). The performance targets for certain performance-based restricted stock units have not been established and therefore expense is not currently recognized. Expense associated with these performance-based awards will be recognized in future periods when performance targets are established. Results for prior periods have not been restated.

Total stock-based compensation expense for the year ending December 31, 2006, was $43.9 million. This amount reflects a reduction of $.3 million of previously recognized compensation cost for restricted stock units related to the estimated number of awards expected to be forfeited. This adjustment is not considered material for reporting as a cumulative effect of a change in accounting principle. Measured but unrecognized stock-based compensation expense at December 31, 2006, was approximately $50 million, which does not include the effect of estimated forfeitures of $1.9 million. This amount is comprised of approximately $13 million related to stock options and approximately $37 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.9 years.

As a result of adopting SFAS No. 123(R), our *income from continuing operations before income taxes* and *net income* for the year ending December 31, 2006, are approximately $18.4 million and $11.3 million lower, respectively, than if we continued to account for share-based compensation under APB No. 25. For the year ending December 31, 2006, both basic and diluted earnings per share are $.02 lower due to the implementation of SFAS No. 123(R).

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The following table illustrates the effect on *net income* and *earnings per common share* for the years ending December 31, 2005 and 2004, if we had applied the fair value recognition provisions of SFAS No. 123 to options granted. For purposes of this pro forma disclosure, the value of the options was estimated using a Black-Scholes option pricing model and amortized to expense over the vesting period of the options.

	Years Ended December 31,	
	2005	2004
	(Dollars in millions, except per share amounts)	
Net income, as reported	$ 313.6	$ 163.7
Add: Stock-based employee compensation expense included in the consolidated statement of income, net of related tax effects	8.9	8.9
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(17.0)	(25.1)
Pro forma net income	$ 305.5	$ 147.5
Earnings per common share:		
Basic as reported	$ .55	$ .31
Basic pro forma	$ .54	$ .28
Diluted as reported	$ .53	$ .31
Diluted pro forma	$ .52	$ .28

Pro forma amounts for 2005 include compensation expense from awards of our company stock made in 2005, 2004, 2003, and 2002. Pro forma amounts for 2004 include compensation expense from awards made in 2004, 2003, 2002, and 2001. Also included in 2004 pro forma expense is $3.3 million of incremental expense associated with a stock option exchange program.

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 issuable restricted stock units. *Diluted earnings (loss) per common share* includes any dilutive effect of stock options, unvested 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)*.

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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 2005, the FASB ratified EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). The consensus states that two or more inventory purchase and sales transactions with the same counterparty that are entered into in contemplation of one another should be combined as a single exchange transaction for purposes of applying APB Opinion No. 29, Accounting for Nonmonetary Transactions. A nonmonetary exchange of inventory within the same line of business where finished goods inventory is transferred in exchange for the receipt of either raw materials or work in process inventory should be recognized at fair value by the entity transferring the finished goods inventory if fair value is determinable within reasonable limits and the transaction has commercial substance. All other nonmonetary exchanges of inventory within the same line of business should be recognized at the carrying amount of the inventory transferred. EITF 04-13 is effective for new arrangements entered into, and modifications or renewals of existing arrangements, beginning in the first reporting period beginning after March 15, 2006. We applied this Issue during 2006 with no significant impact on our Consolidated Financial Statements.

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140 (SFAS No. 155). With regard to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, (SFAS No. 133) this Statement permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only and principal-only strips are not subject to the requirements of SFAS No. 133, and requires the holder of an interest in securitized financial assets to determine whether the interest is a freestanding derivative or contains an embedded derivative requiring bifurcation. SFAS No. 155 also amends SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, (SFAS No. 140) to eliminate a restriction on the passive derivative financial instruments that a qualifying special purpose entity may hold. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. The fair value election regarding hybrid financial instruments may also be applied upon adoption of SFAS No. 155 to hybrid financial instruments that had been bifurcated prior to adoption of SFAS No. 155. We applied the provisions of SFAS No. 155 beginning in January 2007 with no impact on our Consolidated Financial Statements.

In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets, an amendment of FASB Statement No. 140 (SFAS No. 156). This Statement amends SFAS No. 140 with respect to the accounting for separately recognized servicing assets and liabilities from undertaking an obligation to service a financial asset by entering into a servicing contract. SFAS No. 156 is effective as of the beginning of an entity s first fiscal year that begins after September 15, 2006. We applied the provisions of SFAS No. 156 beginning in January 2007 with no impact on our Consolidated Financial Statements.

In April 2006, the FASB issued a Staff Position (FSP) on a previously issued Interpretation (FIN), FSP FIN 46(R)-6, Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R). When determining the variability of an entity in applying FIN 46(R), a reporting enterprise must analyze the design of the entity and consider the nature of the risks in the entity, and determine the purpose for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders. The FSP is

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effective beginning in the third quarter of 2006 on a prospective basis. We applied this FSP with no impact on our Consolidated Financial Statements.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). The Interpretation clarifies the accounting for uncertainty in income taxes under FASB Statement No. 109, Accounting for Income Taxes. The Interpretation prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

FIN 48 is effective for fiscal years beginning after December 15, 2006. The cumulative effect of applying the Interpretation must be reported as an adjustment to the opening balance of retained earnings in the year of adoption. We adopted FIN 48 beginning January 1, 2007, as required. The net impact of the cumulative effect of adopting FIN 48 is expected to be in the range of a $10 million to $20 million decrease in retained earnings.

In June 2006, the FASB ratified EITF No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation) (EITF 06-3). EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to APB Opinion No. 22 Disclosure of Accounting Policies. This is effective for interim and annual reporting periods beginning after December 15, 2006 and will require the financial statement disclosure of any significant taxes recognized on a gross basis. We are reviewing the presentation in our Consolidated Financial Statements and will apply the disclosure provisions of EITF 06-3 with our first quarter 2007 filing.

In September 2006, the 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 is effective for fiscal years beginning after November 15, 2007 and is generally applied prospectively. We will assess the impact of SFAS No. 157 on our Consolidated Financial Statements.

In September 2006, the FASB issued FSP AUG AIR-1, Accounting for Planned Major Maintenance Activities (FSP AUG AIR-1). This FSP addresses the planned major maintenance of assets and prohibits the use of the accrue-in-advance method of accounting for these activities in annual and interim reporting periods. The FSP continues to allow the direct expense, built-in overhaul and deferral methods. FSP AUG AIR-1 requires disclosure of the method of accounting for planned major maintenance activities as well as information related to the change from the accrue-in-advance method to another method. This FSP is effective for the first fiscal year beginning after December 15, 2006 and should be applied retrospectively. We adopted this FSP in January 2007 with no significant impact on our Consolidated Financial Statements.

In December 2006, the FASB issued FSP EITF 00-19-2, Accounting for Registration Payment Arrangements (FSP EITF 00-19-2). The FSP specifies the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate agreement or included as a provision of a financial instrument or other agreement, should be recognized and measured separately in accordance with FASB SFAS No. 5, Accounting for Contingencies and related literature. FSP EITF 00-19-2 further clarifies that a financial instrument subject to a registration payment arrangement should be accounted for in accordance with other applicable generally accepted accounting principles without regard to the contingent obligation to transfer consideration. The FSP applies immediately to registration payment arrangements and the

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financial instruments subject to those arrangements that are entered into or modified subsequent to December 21, 2006. Whereas, for registration payment arrangements and the financial instruments subject to those arrangements entered into prior to its issuance, the FSP applies to our financial statements for the fiscal year beginning in 2007. We adopted the provisions of FSP EITF 00-19-2 beginning in January 2007 with no impact on our Consolidated Financial Statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 establishes a fair value option permitting entities to elect the option to measure eligible financial instruments and certain other items at fair value on specified election dates. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, with a few exceptions, is irrevocable and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007 and should not be applied retrospectively to fiscal years beginning prior to the effective date, except as permitted for early adoption. Early adoption is permitted as of the beginning of a fiscal year provided the entity makes that choice in the first 120 days of the fiscal year and elects to simultaneously adopt the provisions of SFAS No. 157. At the effective date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. We will assess the impact of SFAS No. 159 on our Consolidated Financial Statements.

Note 2. Discontinued Operations

The businesses discussed below represent components that have been sold as of December 31, 2006, and are classified as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the years ended December 31, 2006, 2005, and 2004. *Loss from discontinued operations before income taxes* for the year ended December 31, 2004, includes charges of approximately $153 million to increase our accrued liability associated with certain Quality Bank litigation matters. (See Note 15.) The *provision for income taxes* for the year ended December 31, 2004, is less than the federal statutory rate due primarily to the effect of net Canadian tax benefits realized from the sale of the Canadian straddle plants partially offset by the United States tax effect of earnings associated with these assets.

	2006	2005 (Millions)	2004
Revenues	$	$	$ 353.4
Loss from discontinued operations before income taxes	$ (39.3)	$ (3.9)	$ (121.3)
Gain on sales		.5	200.5

Benefit (provision) for income taxes	15.0	1.3	(8.7)
Income (loss) from discontinued operations	$ (24.3)	$ (2.1)	$ 70.5

2006 Activities

During 2006, we recorded charges of $19.2 million for an adverse arbitration award related to our former chemical fertilizer business and a $6 million accrual for a loss contingency in connection with a former exploration

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

business. In addition, we made a $14.7 million accrual associated with an oil purchase contract related to our former Alaska refinery.

2004 Completed Transactions

Canadian straddle plants

On July 28, 2004, we completed the sale of the Canadian straddle plants for approximately $544 million and recognized a $189.8 million pre-tax gain on the sale. These assets were previously written down to estimated fair value, resulting in impairments of $41.7 million during 2003 and $36.8 million in 2002. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These operations were part of the Midstream segment.

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline operations for approximately $304 million. We received $279 million in cash at the time of sale and $25 million in cash during the second quarter of 2004. Based on information we obtained throughout the sales negotiations process, we recorded impairments of $8 million in 2003 and $18.4 million in 2002. We recognized a $3.6 million pre-tax gain on the sale during first quarter 2004. These operations were part of the previously reported Petroleum Services segment.

We are party to a pending matter involving pipeline transportation rates charged to our former Alaska refinery in prior periods. While we have no loss exposure in this matter, favorable resolution could result in a refund.

Note 3. Investing Activities

Investing Income

Investing income for the years ended December 31, 2006, 2005 and 2004, is as follows:

	2006	2005	2004
		(Millions)	
Equity earnings*	$ 98.9	$ 65.6	$ 49.9
Loss from investments*		(109.1)	(35.5)
Impairments of cost-based investments	(20.4)	(2.2)	(28.5)
Interest income and other	94.5	69.4	62.1
Total	$ 173.0	$ 23.7	$ 48.0

* Items also included in *segment profit*. (See Note 17.)

Loss from investments for the year ended December 31, 2005, includes:

- An $87.2 million impairment of our investment in Longhorn Partners Pipeline L.P. (Longhorn), which is included in our Other segment;

- A $23 million impairment of our investment in Aux Sable Liquid Products, L.P. (Aux Sable), which is included in our Power segment.

Loss from investments for the year ended December 31, 2004, includes:

- A $10.8 million impairment of our Longhorn investment;

- $6.5 million net unreimbursed Longhorn recapitalization advisory fees;

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A $16.9 million impairment of our investment in Discovery Producer Services, L.L.C. (Discovery), which is included in our Midstream segment.

Impairments of cost-based investments for the year ended December 31, 2006, includes a $16.4 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 interest is reported as a cost method investment; previously, we accounted for our working interest using the proportionate consolidation method.

Impairments of cost-based investments for the year ended December 31, 2004, includes a $20.8 million impairment of our investment in an Indonesian toll road, primarily due to increased uncertainty of the Indonesian economy.

Investments

Investments at December 31, 2006 and 2005, are as follows:

	2006	2005
	(Millions)	
Equity method		
Gulfstream Natural Gas System, L.L.C. 50%	$ 387.5	$ 395.4
Discovery Producer Services, L.L.C. 60%*	221.2	227.9
Petrolera Entre Lomas S.A. 40.8%	58.8	51.9
ACCROVEN 49.3%	57.4	60.0
Other	89.5	95.9
	814.4	831.1
Cost method	51.6	56.7
	$ 866.0	$ 887.8

* We own 20% directly and 40% indirectly through Williams Partners L.P., of which we own approximately 22.5%.

The difference 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 discussed below, received from companies accounted for by the equity method were $115.6 million in 2006 and $447.4 million in 2005. These transactions reduced the carrying value of our investments.

Gulfstream

In 2005, we received a $310.5 million distribution from Gulfstream Natural Gas System, L.L.C. (Gulfstream) following its debt offering. We also received dividends from Gulfstream of $41.5 million in 2006 and $60.5 million in 2005.

Discovery

During 2005, our Midstream subsidiary acquired an additional 16.67 percent in Discovery, which was later reduced by 6.67 percent due to a nonaffiliated member exercising its purchase option. After these transactions, we hold a 60 percent interest in Discovery. We continue to account for this investment under the equity method due to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Additionally, we contributed $40.7 million during 2005 to Discovery for planned capital expenditures. Each owner contributed an amount equal to their respective ownership percentage, thus having no impact on the overall ownership allocation. We received distributions from Discovery of $27.2 million in 2006 and $31.3 million in 2005, which reduced the carrying value of our investment.

Longhorn

Based on management s outlook for Longhorn at the end of the second quarter 2005, we assessed our equity investment in Longhorn to determine if there had been an other-than-temporary decline in its fair value. As a result, we recorded an impairment of $49.1 million. In the fourth quarter of 2005, management of Longhorn decided to pursue a strategy of the sale of Longhorn. Based on initial indications from potential buyers, we determined that our Longhorn investment would require full impairment. Therefore, in fourth quarter 2005, we recorded a $38.1 million impairment to write off the remaining investment in Longhorn.

We continue to have an equity ownership interest in Longhorn, including 94.7 percent of the Class B Interests and 21.3 percent of the Common Interests, even though the management of Longhorn completed an asset sale of the pipeline during the third quarter of 2006. Summarized results of operations of equity method investments in 2006, as presented below, reflect the impact of Longhorn s loss on this sale. As a result of the sale, we received full payment of the $10 million secured bridge loan that we provided Longhorn during 2005.

Aux Sable

During 2005, we decided to solicit sales offers for our equity investment in Aux Sable, a natural gas liquids extraction and fractionation facility. Based on initial indications of potential sales proceeds, management concluded that there was an other-than-temporary decline in fair value below carrying value. Accordingly, we recorded an impairment of $23 million.

Summarized Financial Position and Results of Operations of Equity Method Investments

Financial position at December 31:

	2006	2005
	(Millions)	
Current assets	$ 296.5	$ 470.5
Noncurrent assets	3,301.7	3,674.4
Current liabilities	198.0	362.0
Noncurrent liabilities	1,311.5	1,225.6

Results of operations for the years ended December 31:

	2006	2005	2004
		(Millions)	
Gross revenue	$ 970.4	$ 1,337.5	$ 1,064.7
Operating income	401.2	236.3	185.0
Net income (loss)	(14.6)	105.3	107.8

Guarantees on Behalf of Investees

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN. These expire in January 2008 and have no carrying value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006 and 2005.

Note 4. Asset Sales and Other Accruals

Significant gains or losses from asset sales and other accruals or adjustments reflected in *other (income) expense net* within *segment costs and expenses* for the years noted are as follows:

	Year Ended December 31,		
	2006	2005	2004
		(Millions)	
Exploration & Production			
Gains on sales of certain natural gas properties	$	$ (29.6)	$
Loss provision related to an ownership dispute			15.4
Midstream			
Accrual for Gulf Liquids litigation contingency. Associated with this contingency is an interest expense accrual of $22 million, which is included in *interest accrued* (see Note 15)	72.7		
Arbitration award on a Gulf Liquids insurance claim dispute			(93.6)
Power			
Accrual for litigation contingencies	4.8	82.2	
Reduction of contingent obligations associated with our former distributive power generation business	(12.7)		
Other			
Environmental accrual related to the Augusta refinery facility			11.8

Additional Items

Costs and operating expenses within our Gas Pipeline segment reported in 2005 includes:

- An adjustment to reduce costs by $12.1 million to correct the carrying value of certain liabilities recorded in prior periods;

- Adjustments of $37.3 million reflected as increases in costs and operating expenses related to $32.1 million of prior period accounting and valuation corrections for certain inventory items and an accrual of $5.2 million for contingent refund obligations.

Selling, general and administrative expenses within our Gas Pipeline segment in 2005 includes:

An adjustment to reduce costs by $5.6 million to correct the carrying value of certain liabilities recorded in prior periods;

A $17.1 million reduction in pension expense for the cumulative impact of a correction of an error attributable to 2003 and 2004. (See Note 7.)

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Note 5. Provision for Income Taxes

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

	2006	2005 (Millions)	2004
Current:			
Federal	$ (9.0)	$ 225.0	$ 11.0
State	2.7	2.8	(13.7)
Foreign	43.4	31.4	11.0
	37.1	259.2	8.3
Deferred:			
Federal	140.9	(52.9)	75.1
State	3.3	15.6	38.7
Foreign	25.0	(8.0)	9.2
	169.2	(45.3)	123.0
Total provision	$ 206.3	$ 213.9	$ 131.3

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:

	2006	2005 (Millions)	2004
Provision at statutory rate	$ 188.7	$ 186.0	$ 78.6
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	6.5	21.5	27.9
Foreign operations net	25.3	6.7	6.1
Utilization/valuation/expiration of charitable contributions	(9.3)	8.4	13.8
Federal income tax litigation	(40.0)	3.6	1.6
Non-deductible convertible debenture expenses	9.5		
Adjustment of excess deferred taxes	7.4	(20.2)	
Non-deductible penalties		17.7	(.9)
Other net	18.2	(9.8)	4.2
Provision for income taxes	$ 206.3	$ 213.9	$ 131.3

Utilization of foreign operating loss carryovers reduced the provision for income taxes by $3 million and $13 million in 2006 and 2005, respectively. During 2004, the utilization of foreign tax credits reduced the provision for income taxes by $12 million.

Income from continuing operations before income taxes and cumulative effect of change in accounting principle includes $141 million, $59 million, and $51 million of international income in 2006, 2005, and 2004, respectively.

We provide for income taxes using the asset and liability method as required by SFAS No. 109, Accounting for Income Taxes. As a result of additional analysis of our tax basis and book basis asset and liabilities, we recorded a tax provision of $7.4 million and a tax benefit of $20.2 million in 2006 and 2005, respectively, to adjust the overall deferred income tax liabilities on the Consolidated Balance Sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 record a liability for probable tax contingencies. In association with this liability, we record an estimate of related interest and tax exposure as a component of our current tax provision. The impact of this accrual is included within *other net* in our reconciliation of the tax provision to the federal statutory rate.

One of our wholly owned subsidiaries, Transco Coal Gas Company, was engaged in a dispute with the Internal Revenue Service (IRS) in which the principle issue was the recapture of certain income tax credits associated with the construction and operation of a coal gasification plant in North Dakota by Great Plains Gasification Associates, a partnership in which Transco Coal Gas Company was a partner in the 1980 s. The IRS took alternative positions that alleged a disposition date for purposes of tax credit recapture that was earlier than the position taken in the partnership tax return. After settlement negotiations failed, the matter was tried before the U.S. Tax Court in February 2005. On December 27, 2006, the Tax Court ruled that the partnership utilized the appropriate disposition date for purposes of tax credit recapture.

Significant components of *deferred tax liabilities* and *deferred tax assets* as of December 31, 2006, and 2005, are as follows:

	2006	2005
	(Millions)	
Deferred tax liabilities:		
Property, plant and equipment	$ 2,898.5	$ 2,718.9
Derivatives net	223.4	61.3
Investments	210.2	158.6
Other	100.4	96.7
Total deferred tax liabilities	3,432.5	3,035.5
Deferred tax assets:		
Minimum tax credits	145.6	163.8
Accrued liabilities	510.2	285.2
Receivables	17.3	39.3
Federal carryovers	182.8	286.0
Foreign carryovers	36.1	30.4
Other	33.9	
Total deferred tax assets	925.9	804.7
Less valuation allowance	36.1	37.1

Net deferred tax assets	889.8	767.6
Overall net deferred tax liabilities	$ 2,542.7	$ 2,267.9

The *valuation allowance* at December 31, 2006, serves to reduce the recognized tax benefit associated with foreign carryovers to an amount that will, more likely than not, be realized. The *valuation allowance* at December 31, 2005 serves to reduce the recognized tax benefit associated with charitable contribution carryovers and foreign carryovers to an amount that will, more likely than not, be realized.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2006, totaled approximately $198 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.

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Cash payments for income taxes (net of refunds) were $79 million, $230 million, and $8 million in 2006, 2005, and 2004, respectively. Cash tax payments include settlements with taxing authorities associated with prior period audits of $42 million and $204 million in 2006 and 2005, respectively.

At December 31, 2006, federal net operating loss carryovers are $509 million. We expect to utilize our net operating loss carryovers prior to expiration in 2022 through 2025. We also expect to utilize $13 million of charitable contribution carryovers prior to their expiration in 2007 through 2010. We do not expect to be able to utilize our $36.1 million foreign deferred tax assets related to carryovers.

In June 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). We adopted the Interpretation beginning January 1, 2007. The impact of this adoption is more fully described in Note 1.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share for the years ended December 31, 2006, 2005 and 2004, are:

	2006	2005	2004
	(Dollars in millions, except per-share amounts; shares in thousands)		
Income from continuing operations available to common stockholders for basic and diluted earnings per share(1)	$ 332.8	$ 317.4	$ 93.2
Basic weighted-average shares(2)	595,053	570,420	529,188
Effect of dilutive securities:			
Unvested restricted stock units(3)	1,029	2,890	2,631
Stock options	4,440	4,989	3,792
Convertible debentures	8,105	27,548	
Diluted weighted-average shares	608,627	605,847	535,611
Earnings per common share from continuing operations:			
Basic	$ .56	$ .55	$ .18
Diluted	$ .55	$ .53	$ .18

(1) The years ended December 31, 2006 and 2005, include $3.0 million and $10.2 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.

(See discussion of antidilutive items below.)

(2) During January 2006, we issued 20.2 million shares of common stock related to a conversion offer for our 5.5 percent convertible debentures. In February 2005 and October 2004, we issued 10.9 million and 33.1 million, respectively, common shares associated with our FELINE PACS units.

(3) The unvested restricted stock units outstanding at December 31, 2006, will vest over the period from January 2007 to December 2009.

Approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of diluted earnings per common share for the year ended December 31, 2004. Inclusion of these shares would have an antidilutive effect on diluted earnings per common share. If no other components used to calculate diluted earnings per common share change, we estimate the assumed conversion of convertible debentures would have become dilutive and therefore would be included in diluted earnings per common share at an *income from continuing operations available to common stockholders* amount of $198.1 million for the year ended December 31, 2004.

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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.

	2006	2005	2004
Options excluded (millions)	3.6	4.7	8.5
Weighted-average exercise prices of options excluded	$ 36.14	$ 35.22	$ 28.21
Exercise price ranges of options excluded	$ 26.79 - $42.29	$ 22.68 - $42.29	$ 14.61 - $42.29
Fourth quarter weighted-average market price	$ 25.77	$ 22.41	$ 14.41

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 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 medical and life insurance benefits (other postretirement benefits) to certain eligible participants. Generally, employees hired after December 31, 1991, are not eligible for these 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 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.

SFAS No. 158 Adoption

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106 and 132(R) (SFAS No. 158). This Statement requires sponsors of defined benefit pension and other postretirement benefit plans to recognize the funded status of their pension and other postretirement benefit plans in the statement of financial position, measure the fair value of plan assets and benefit obligations as of the date of the fiscal year-end statement of financial position, and provide additional disclosures. On December 31, 2006, we adopted the recognition and disclosure provisions of SFAS No. 158, the effect of which has been reflected in the accompanying consolidated financial statements as of December 31, 2006, as described below. The adoption had no impact on the consolidated financial statements at December 31, 2005 or 2004. SFAS No. 158 s provisions regarding the change in the measurement date of postretirement benefit plans are not applicable as we already use a measurement date of December 31. There is no effect on our Consolidated Statement of Income for the year ended December 31, 2006, or for any periods presented related to the adoption of SFAS No. 158, nor will our future operating results be affected by the adoption.

Prior to the adoption of SFAS No. 158, accounting rules allowed for the delayed recognition of certain actuarial gains and losses caused by differences between actual and assumed outcomes, as well as charges or credits caused by plan changes impacting the benefit obligations which were attributed to participants prior service. These unrecognized net actuarial gains or losses and unrecognized prior service costs or credits represented the difference between the plans funded status and the amount recognized on the Consolidated Balance Sheet. In accordance with SFAS No. 158, we recorded adjustments to *accumulated other comprehensive loss*, net of income taxes, to recognize the funded status of our pension and other postretirement benefit plans on our Consolidated Balance Sheet. For our FERC-regulated gas pipelines, we recorded the adjustment to *net regulatory liabilities* for our other postretirement benefit plans. These

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adjustments represent the previously unrecognized net actuarial gains and losses and unrecognized prior service costs or credits. The detail of the effect of adopting SFAS No. 158 is provided in the following table.

The adjustments recorded to *accumulated other comprehensive loss* and *net regulatory liabilities* will be recognized as components of *net periodic pension expense* or *net periodic other postretirement benefit expense* and amortized over future periods in accordance with SFAS No. 87, Employers Accounting for Pensions, and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions, in the same manner as prior to the adoption of SFAS No. 158. Actuarial gains and losses that arise in subsequent periods and are not recognized as *net periodic pension* or *other postretirement benefit expense* in the same period will now be recognized in *other comprehensive income (loss)* and *net regulatory liabilities.* These amounts will be recognized subsequently as a component of *net periodic pension* or *other postretirement benefit expense* following the same basis as the amounts recognized in *accumulated other comprehensive loss* and *net regulatory liabilities* upon adoption of SFAS No. 158.

The effects of adopting SFAS No. 158 on our Consolidated Balance Sheet at December, 31, 2006, are presented in the following tables. The disclosures in this note exclude the impact of a pension plan of an equity method investee.

	Prior to SFAS No. 158 Adoption(1)	Effect of SFAS No. 158 Adoption(1) (Millions)	After SFAS No. 158 Adoption(1)
Balances related to pension plans within:			
Assets:			
Noncurrent assets	$ 330.8	$ (216.7)	$ 114.1
Liabilities:			
Current liabilities		1.0	1.0
Net regulatory liabilities	10.5	2.2	12.7
Noncurrent liabilities	18.9	20.2	39.1
Deferred income tax liabilities	(3.1)	(91.6)	(94.7)
Stockholders equity:			
Accumulated other comprehensive loss	(4.9)	(148.5)	(153.4)
Balances related to other postretirement benefits plans within:			
Assets:			
Noncurrent assets	$ 13.6	$ (13.6)	$
Liabilities:			
Current liabilities	10.6	(1.4)	9.2
Net regulatory liabilities	(8.0)	12.8	4.8
Noncurrent liabilities	133.2	(10.5)	122.7
Deferred income tax liabilities		(12.5)	(12.5)
Stockholders equity:			
Accumulated other comprehensive loss		(2.0)	(2.0)

(1) Amounts in brackets represent a reduction within the line item balance included on the Consolidated Balance Sheet.

Prior to the adoption of SFAS No. 158, we had computed an additional minimum pension liability of $10.2 million. The effect of recognizing this additional minimum pension liability is included as *accumulated other comprehensive loss* of $4.9 million (net of taxes of $3.1 million) and *net regulatory liabilities* of $2.2 million under the Prior to SFAS No. 158 Adoption column within the previous table.

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Accumulated other comprehensive loss at December 31, 2006 includes the following:

	Pension Benefits		Other Postretirement Benefits	
	Gross	Net of Tax	Gross	Net of Tax
	(Millions)			
Amounts not yet recognized in net periodic benefit expense:				
Unrecognized prior service cost	$ (5.7)	$ (3.5)	$ (6.7)	$ (4.1)
Unrecognized net actuarial gains (losses)	(242.4)	(149.9)	(7.8)	2.1
Amounts expected to be recognized in net periodic benefit expense (income) in 2007:				
Prior service cost (credit)	$ (.4)	$ (.3)	$ 1.1	$ .7
Net actuarial (gains) losses	16.5	10.2		(.1)

Net regulatory liabilities includes unrecognized prior service credits of $4.6 million and unrecognized net actuarial gains of $8.2 million associated with our FERC-regulated gas pipelines. These amounts have not yet been recognized in *net periodic other postretirement benefit expense.* The prior service credit included in *net regulatory liabilities* and expected to be recognized in *net periodic other postretirement benefit expense* in 2007 is $1.5 million. No actuarial gains included in *net regulatory liabilities* are expected to be recognized in *net periodic other postretirement benefit expense* in 2007.

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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. It also presents a reconciliation of the funded status of these benefit plans to the amounts recorded in the Consolidated Balance Sheet at December 31, 2005. The annual measurement date for our plans is December 31.

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
	(Millions)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 897.4	$ 893.0	$ 375.4	$ 268.4
Service cost	22.1	21.5	3.2	3.3
Interest cost	50.9	47.6	17.3	20.3
Plan participants contributions			4.7	4.3
Settlement benefits paid		(4.0)		
Benefits paid	(52.4)	(58.2)	(24.0)	(24.0)
Plan amendments				51.2
Actuarial (gain) loss	13.3	(2.5)	(64.2)	51.9
Benefit obligation at end of year	931.3	897.4	312.4	375.4
Change in plan assets:				
Fair value of plan assets at beginning of year	887.6	835.5	163.6	158.9
Actual return on plan assets	126.8	56.4	21.6	9.5
Employer contributions	43.3	57.9	14.6	14.9
Plan participants contributions			4.7	4.3
Benefits paid	(52.4)	(58.2)	(24.0)	(24.0)
Settlement benefits paid		(4.0)		
Fair value of plan assets at end of year	1,005.3	887.6	180.5	163.6
Funded status overfunded (underfunded)	$ 74.0	(9.8)	$ (131.9)	(211.8)
Unrecognized net actuarial loss		309.7		74.4
Unrecognized prior service cost		5.1		1.7
Prepaid (accrued) benefit cost		$ 305.0		$ (135.7)
Accumulated benefit obligation	$ 871.6	$ 831.4		

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Amounts recognized in the Consolidated Balance Sheet at December 31, 2005 consist of:

	Pension Benefits	Other Postretirement Benefits
	(Millions)	
Prepaid benefit cost	$ 312.6	$
Accrued benefit cost	(16.8)	(135.7)
Regulatory asset	2.3	
Accumulated other comprehensive loss (before tax)	6.9	
Prepaid (accrued) benefit cost	$ 305.0	$ (135.7)

The net underfunded/overfunded status of our pension plans presented in the previous table is recognized in the December 31, 2006, Consolidated Balance Sheet in *noncurrent assets* as $114.1 million for our overfunded pension plans and in *current liabilities* as $1.0 million and in *noncurrent liabilities* as $39.1 million for our underfunded pension plans. The underfunded status of our other postretirement benefit plans presented in the previous table is recognized in the December 31, 2006, Consolidated Balance Sheet in *current liabilities* as $9.2 million and in *noncurrent liabilities* as $122.7 million. 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 actuarial present value of benefits included in the benefit obligation payable in 2007 for the groups of participants whose benefits are not expected to be paid from plan assets.

The *regulatory asset* shown in 2005 in the table above is the portion of the additional minimum pension liability recognized by our FERC-regulated gas pipelines. As required by FERC accounting guidelines, our FERC-regulated gas pipelines were required to record the effect of an additional minimum pension liability to a *regulatory asset* instead of *accumulated other comprehensive loss.*

The 2006 *actuarial loss* of $13.3 million for our pension plans included in the table of changes in benefit obligation is due primarily to the impact of actual results differing from assumed results such as compensation and participant deaths, offset by the net impact of changes in assumptions utilized to calculate the benefit obligation including the discount rate, mortality and expected form of benefit payments. The 2005 *actuarial gain* of $2.5 million for our pension plans included in the table of changes in benefit obligation reflects a gain of approximately $68 million for the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004. The error was associated with our third-party actuarial computation of the benefit obligation which resulted in the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. This gain is offset substantially by the impact of changes to the discount rates utilized to determine the benefit obligation. The 2006 *actuarial gain* of $64.2 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of changes in assumptions utilized to calculate the benefit obligation including claims costs, health care cost trend rates and the discount rate, as well as actual results differing from assumed results such as participant deaths and terminations prior to retirement. The 2005 *actuarial loss* of

$51.9 million for our other postretirement benefit plans included in the table of changes in benefit obligation is due primarily to the impact of changes in assumptions utilized to calculate the benefit obligation including the health care cost trend rates, discount rate and estimated cost savings related to the Medicare Prescription Drug Act.

The current accounting rules for the determination of *net periodic pension* and *other postretirement 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 *unrecognized net actuarial loss* presented in the previous tables and recorded in *accumulated other comprehensive loss* and *net regulatory liabilities* at December 31, 2006, represents the cumulative net deferred losses from these types of differences or changes which have not yet

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

been recognized in the Consolidated Statement of Income. A portion of the net unrecognized gains and losses are amortized over the participants average remaining future years of service, which is approximately 12 years for our pension plans and 13 years for our other postretirement benefit plans.

We have multiple pension plans that are aggregated as prescribed for reporting purposes including both overfunded and underfunded pension plans.

Information for pension plans with a projected benefit obligation in excess of plan assets:

	December 31, 2006	December 31, 2005
	(Millions)	
Projected benefit obligation	$ 479.8	$ 428.6
Fair value of plan assets	439.7	359.7

Information for pension plans with an accumulated benefit obligation in excess of plan assets:

	December 31, 2006	December 31, 2005
	(Millions)	
Accumulated benefit obligation	$ 18.9	$ 16.7
Fair value of plan assets		

Net Periodic Pension and Other Postretirement Benefit Expense (Income)

Net periodic pension expense (income) and *other postretirement benefit expense* for the years ended December 31, 2006, 2005, and 2004, consists of the following:

	Pension Benefits 2006	2005	2004
		(Millions)	
Components of net periodic pension expense (income):			
Service cost	$ 22.1	$ 21.5	$ 24.0
Interest cost	50.9	47.6	50.5
Expected return on plan assets	(66.8)	(71.1)	(64.9)
Amortization of prior service credit	(.6)	(.4)	(1.5)
Recognized net actuarial (gain) loss	20.6	(4.9)	9.4
Regulatory asset amortization (deferral)	(.2)	.6	2.0

Settlement/curtailment expense		2.7	.1
Net periodic pension expense (income)	$ 26.0	$ (4.0)	$ 19.6

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Other Postretirement Benefits		
	2006	2005	2004
	(Millions)		
Components of net periodic other postretirement benefit expense:			
Service cost	$ 3.2	$ 3.3	$ 3.2
Interest cost	17.3	20.3	18.8
Expected return on plan assets	(11.0)	(11.5)	(12.4)
Amortization of transition obligation			2.7
Amortization of prior service cost (credit)	(.4)	(4.3)	.6
Recognized net actuarial loss		3.2	
Regulatory asset amortization	7.1	6.8	6.7
Net periodic other postretirement benefit expense	$ 16.2	$ 17.8	$ 19.6

Net periodic pension expense (income) for 2005 includes a $17.1 million reduction to expense to record the cumulative impact of a correction of an error determined to have occurred in 2003 and 2004. The error was associated with our third-party actuarial computation of annual *net periodic pension expense* which resulted from the identification of errors in certain Transco participant data involving annuity contract information utilized for 2003 and 2004. The adjustment is reflected as $16.1 million within *recognized net actuarial (gain) loss* and $1.0 million within *regulatory asset amortization (deferral).*

The differences in the amount of actuarially determined *net periodic other postretirement benefit expense* 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, 2006, we have a regulatory asset of $8.5 million for Transco and a regulatory liability of $13.3 million for Northwest Pipeline related to these deferrals. At December 31, 2005, we had a regulatory asset of $24.3 million for Transco and a regulatory liability of $10.8 million at Northwest Pipeline related to these deferrals. These amounts will be reflected in future rates based on Transco and Northwest Pipeline s rate structures.

Key Assumptions

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2006, and 2005, are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	5.80%	5.65%	5.80%	5.60%
Rate of compensation increase	5.00	5.00	N/A	N/A

The weighted-average assumptions utilized to determine *net periodic pension and other postretirement benefit expense* for the years ended December 31, 2006, 2005, and 2004, are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	2004	2006	2005	2004
Discount rate	5.65%	5.86%	6.25%	5.60%	5.63%	6.25%
Expected long-term rate of return on plan assets	7.75	8.50	8.50	6.95	7.45	8.50
Rate of compensation increase	5.00	5.00	5.00	N/A	N/A	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The discount rates for our pension and other postretirement benefit plans were determined separately based on an approach specific to our plans and their respective expected benefit cash flows. With the assistance of our third-party actuary, the plans were analyzed and discount rates based on a yield curve comprised of high-quality corporate bonds published by a large securities firm were matched to a highly correlated published index of high-quality corporate bonds. Based on an analysis performed between each of the plans yield curve discount rates and the index, a formula was developed to determine the December 31, 2006, discount rates based upon the year-end published index.

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 the capital market projections provided by our independent investment consultant for the asset classifications in which the portfolio is invested and the target weightings of each asset classification.

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 to our third-party actuary s 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 2007 is 9.3 percent, and systematically decreases to 5.5 percent by 2013. 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	$ 3.3	$ (4.1)
Effect on postretirement benefit obligation	60.5	(48.1)

Medicare Prescription Drug Act

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D) beginning in 2006 as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plans for retirees include prescription drug coverage. Prior to 2005, our plans were amended to coordinate and pay secondary to any part of Medicare, including prescription drug benefits covered by Medicare Part D, which resulted in a decrease in the benefit obligation of $75.5 million. Beginning in 2005, the net reduction to the obligation was being amortized over approximately seven years which was the participants average remaining years of service to full eligibility for benefits. It is reflected in the *amortization of prior service credit* in the table of components of *net periodic other postretirement benefit expense* for 2005.

Due to anticipated difficulties to administer our plans as previously amended to coordinate and pay secondary to Medicare Part D in 2006, we amended our plans in June 2005 to generally provide primary prescription drug coverage and apply for the federal subsidy in 2006. As a result of the amendment, generally our plans are designed to be actuarially equivalent to the standard coverage under Medicare Part D. The amendment increased our benefit obligation by $51.2 million at June 30, 2005, and is reflected as a *plan amendment* in the table of changes in benefit obligation for 2005. Beginning in the third quarter of 2005, the increase to the obligation is being amortized over the participants average remaining years of service to full eligibility for benefits, which is approximately seven years. *Net periodic other postretirement benefit expense* for 2005, reflects an increase of $7.1 million, including an increase in *recognized net actuarial loss* of $.3 million, an increase in *service cost* of $.3 million, an increase in *interest cost* of $2.6 million, and an increase in *amortization of prior service credit* of $3.9 million, resulting from the plan amendment. We are continuing to evaluate coordination with Medicare Part D as a strategy to decrease our benefit obligation in the future and will closely monitor the development of systems and capabilities of third-party administrators to coordinate prescription drug benefits with the Centers for Medicare & Medicaid Services.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006, and 2005 and target asset allocation at December 31, 2006, by asset category.

	Pension Benefits			Other Postretirement Benefits		
	2006	2005	Target	2006	2005	Target
Equity securities	82%	81%	84%	77%	78%	80%
Debt securities	12	13	16	12	13	20
Other	6	6		11	9	
	100%	100%	100%	100%	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 38 percent and 37 percent of the pension plans weighted-average assets at December 31, 2006, and 2005, respectively, and 27 percent and 26 percent of the other postretirement benefit plans weighted-average assets at December 31, 2006, and 2005, respectively. Other assets are comprised primarily of cash and cash equivalents for the pension plans and other postretirement benefit plans.

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.

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 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 2006, 11 active investment managers and one passive investment manager managed substantially all of the pension and other postretirement benefit plans funds, each of whom had responsibility for managing a specific portion of these assets.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Periodically, an asset and liability study is performed to determine the optimal asset mix to meet future benefit obligations. The most recent pension asset and liability study was performed in 2001.

Plan Benefit Payments and Employer Contributions

The following are the expected benefits to be paid by the plan 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 (Millions)	Federal Prescription Drug Subsidy
2007	$ 45.5	$ 21.3	$ (2.0)
2008	39.6	21.9	(1.9)
2009	35.7	22.2	(2.1)
2010	33.7	22.3	(2.2)
2011	34.5	21.5	(2.3)
2012-2016	240.3	105.8	(13.4)

We expect to contribute approximately $41 million to our pension plans and approximately $16 million to our other postretirement benefit plans in 2007.

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 plan s guidelines. We match employees contributions up to certain limits. Costs recognized for these plans were $18.7 million in 2006, $16.8 million in 2005, and $16.9 million in 2004. One of our defined contribution plans was amended as of July 1, 2005, to convert one of the funds within the plan to a nonleveraged employee stock ownership plan (ESOP). The 2005 compensation cost related to the ESOP of $.7 million is included in the $16.8 million of contributions, previously mentioned above, and represents the contribution made in consideration for employee services rendered in 2005. It is measured by the amount of cash contributed to the 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. For 2006 and future years, there are no contributions to this ESOP, other than dividend reinvestment, as contributions for purchase of our stock is now restricted within this defined contribution plan.

Note 8. Inventories

Inventories at December 31, 2006, and 2005, are as follows:

	2006	2005
	(Millions)	
Natural gas liquids	$ 77.9	$ 100.0
Natural gas in underground storage	77.6	90.4
Materials, supplies and other	85.9	82.2
	$ 241.4	$ 272.6

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Inventories determined using the LIFO cost method were approximately 11 percent and 8 percent of *inventories* at December 31, 2006 and 2005, respectively. The remaining *inventories* were primarily determined using the average-cost method.

If *inventories* valued using the LIFO cost method at December 31, 2006 and 2005, were valued at current replacement cost, the amounts would increase by $22 million and $59 million, respectively.

Natural gas in underground storage reflects a $32.1 million charge recorded in 2005 for prior period accounting and valuation corrections.

Note 9. Property, Plant and Equipment

Property, plant and equipment net at December 31, 2006, and 2005, is as follows:

	2006	2005
	(Millions)	
Cost:		
Exploration & Production	$ 5,918.2	$ 4,458.9
Gas Pipeline	9,127.3	8,371.1
Midstream Gas & Liquids(1)	4,545.5	4,351.4
Power	155.3	154.9
Other	245.6	235.5
	19,991.9	17,571.8
Accumulated depreciation, depletion and amortization	(5,811.2)	(5,162.6)
	$ 14,180.7	$ 12,409.2

(1) Certain assets above are currently pledged as collateral to secure debt. (See Note 11.)

Depreciation, depletion and amortization expense for *property, plant and equipment net* was $865.1 million in 2006, $739 million in 2005, and $667.4 million in 2004.

Property, plant and equipment net includes approximately $685 million at December 31, 2006, and $374 million at December 31, 2005, of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $414 million at December 31, 2006, and $443 million at December 31, 2005, of capitalized costs related to properties with unproven reserves not yet subject to depletion.

Property, plant and equipment net includes approximately $1.1 billion at December 31, 2006, and $1.2 billion at December 31, 2005, 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

In March 2005, the FASB issued FIN 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143. The Interpretation clarifies that the term conditional asset retirement as used in SFAS No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We adopted the Interpretation on December 31, 2005. In accordance with the Interpretation, we estimated future retirement obligations for certain assets previously considered to have an indeterminate life. As a result, we recorded an increase in *other liabilities and deferred income* of $29.4 million, an increase in *property, plant and equipment net* of $12.2 million, and a *cumulative effect of change in accounting principle* of $1.7 million (net of $1.0 million of taxes). We also recorded a $14.5 million regulatory asset in *other assets and deferred charges* for retirement costs expected to be recovered through regulated rates. Had we implemented the Interpretation at the beginning of 2003, the financial statement impact at December 31, 2004 would not be substantially different than the impact at December 31, 2005.

The asset retirement obligation at December 31, 2006 and 2005 is $333 million and $93 million, respectively. The increase in the obligation in 2006 is due primarily to obtaining additional information that revised our estimation of our asset retirement obligation for certain assets in our Exploration & Production, Gas Pipeline and Midstream segments. Factors affected by the additional information included estimated settlement dates, estimated settlement costs and inflation rates.

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.

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 $44 million of these negative balances at December 31, 2006, and $69 million at December 31, 2005.

On May 26, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million. We had previously deferred $113 million of a gain on sale related to these indemnities. At the date of sale, the deferred revenue and identified obligations related to the indemnities totaled $102 million. The carrying value of this obligation is $33.9 million at December 31, 2006, and $51.3 million at December 31, 2005. The obligation will be settled with a payment of $35 million on July 1, 2007.

Accrued liabilities at December 31, 2006, and 2005, are as follows:

	2006	2005
	(Millions)	
Interest	$ 243.3	$ 245.0
Employee costs	165.8	147.2

Taxes other than income taxes	151.9	141.4
Accrual for Gulf Liquids litigation contingency	94.7*	
Income taxes	80.8	58.2
Accrual for Power litigation contingencies	43.4	52.2
Guarantees and payment obligations related to WilTel	41.1	42.7
Structured indemnity settlement	33.9	19.4
Other	386.5	417.0
	$ 1,241.4	$ 1,123.1

* Includes $22 million of interest

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 11. Debt, Leases and Banking Arrangements

Long-Term Debt

Long-term debt at December 31, 2006 and 2005, is:

	Weighted-Average Interest Rate(1)	December 31, 2006	2005
		(Millions)	
Secured(2)			
6.62%-9.45%, payable through 2016	8.0%	$ 171.7	$ 195.7
Adjustable rate, payable through 2016	6.2%	74.4	572.2
Capital lease obligations	9.3%	2.5	2.8
Unsecured			
5.5%-10.25%, payable through 2033	7.6%	7,690.4	6,867.3
Adjustable rate, due 2008	6.7%	75.0	75.0
Other, payable through 2007	6.0%	.1	.1
Total long-term debt, including current portion		8,014.1	7,713.1
Long-term debt due within one year		(392.1)	(122.6)
Long-term debt		$ 7,622.0	$ 7,590.5

(1) At December 31, 2006.

(2) Includes $246.1 million at December 31, 2006, collateralized by certain fixed assets of two of our Venezuelan subsidiaries with a net book value of $380 million at December 31, 2006.

Revolving credit and letter of credit facilities (credit facilities)

In May 2006, we obtained an unsecured, three-year, $1.5 billion revolving credit facility, replacing our $1.275 billion secured revolving credit facility. The new unsecured facility contains similar terms and financial covenants as the secured facility, but contains additional restrictions on asset sales, certain subsidiary debt and sale-leaseback transactions. The facility is guaranteed by Williams Gas Pipeline Company, LLC and we guarantee obligations of Williams Partners L.P. for up to $75 million. Northwest Pipeline and Transco each have access to $400 million and Williams Partners L.P. has access to $75 million under the facility to the extent not otherwise utilized by us. 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 .25 percent annually) based on the unused portion of the 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, 2006, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 53 percent.

Ratio of debt to capitalization must be no greater than 55 percent for Northwest Pipeline and Transco. At December 31, 2006, we are in compliance with this covenant as our ratio of debt to capitalization, as calculated under this covenant, is approximately 44 percent for Northwest Pipeline and 32 percent for Transco.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Our ratio of EBITDA to interest, on a rolling four quarter basis, must be no less than 2.5 for the period ending December 31, 2007 and 3.0 for the remaining term of the agreement. Through December 31, 2006, we are in compliance with this covenant as we exceed the compliance level by approximately 50 percent.

Our $500 million and $700 million 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 and 2.29 percent for the $500 million and $700 million 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 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 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 facilities are delivered to the investors as described below. Thus, we have no asset securitization or collateral requirements under the facilities. Upon the occurrence of certain credit events, letters of credit under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently, the funding bank can deliver the facilities to the institutional investors, whereby the investors replace the funding bank as lender under the 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	

At December 31, 2006, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at December 31, 2006 (Millions)
$500 million unsecured credit facilities	$ 370.1
$700 million unsecured credit facilities	$ 525.0
$1.5 billion unsecured credit facility	$ 28.8

Exploration & Production s Credit Agreement

Exploration & Production has recently 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 and on natural gas reserves value.

Issuances and retirements

On May 28, 2003, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable after seven years, are convertible at the option of the holder into our common stock at a conversion price of approximately $10.89 per share. In November 2005, we initiated an offer to convert these debentures to shares of our common stock. In January 2006, we converted approximately $220.2 million of the debentures. (See Note 12.)

In April 2006, Transco issued $200 million aggregate principal amount of 6.4 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In April 2006, we retired a secured floating-rate term loan for $488.9 million, including outstanding principal and accrued interest. The loan was due in 2008 and secured by substantially all of the assets of Williams Production RMT Company. The loan was retired using a combination of cash and revolving credit borrowings.

In June 2006, Northwest Pipeline issued $175 million aggregate principal amount of 7 percent senior unsecured notes due 2016 to certain institutional investors in a private debt placement. In October 2006, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

In June 2006, Williams Partners L.P. acquired 25.1 percent of our interest in Williams Four Corners LLC for $360 million. 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 and an equity offering of approximately $225 million in net proceeds. In December 2006, Williams Partners L.P. acquired the remaining 74.9 percent interest in Williams Four Corners LLC for $1.223 billion. The acquisition was completed after Williams Partners L.P. successfully closed a $600 million private debt offering of 7.25 percent senior unsecured notes due 2017, a private equity offering of approximately $350 million of common and Class B units, and a public equity offering of approximately $294 million in net proceeds. The debt and equity issued by Williams Partners L.P. is reported as a component of our consolidated debt balance and minority interest balance, respectively. Williams Four Corners LLC owns certain gathering, processing and treating assets in the San Juan Basin in Colorado and New Mexico.

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)
2007	$ 391.4
2008	238.0
2009	53.1
2010	217.3
2011	1,168.0

Cash payments for interest (net of amounts capitalized) were as follows: 2006 $611 million; 2005 $625 million; and 2004 $849 million.

Leases-Lessee

Future minimum annual rentals under noncancelable operating leases as of December 31, 2006, are payable as follows:

	(Millions)

2007	$	225.4
2008		227.0
2009		205.9
2010		185.8
2011		179.8
Thereafter		1,120.9
Total	$	2,144.8

The above amounts include obligations of approximately $1.9 billion related to a tolling agreement at Power that is accounted for as an operating lease as a result of changes to the contract terms in 2004 after implementation of EITF 01-8. (See Note 1.) Under the tolling agreement, Power has the exclusive right to capacity and fuel conversion services as well as ancillary services associated with electric generation facilities that are currently in

THE WILLIAMS COMPANIES, INC.

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operation in southern California. Current annual rentals under this tolling agreement range from approximately $157 million to $169 million through 2017, with approximately $70 million remaining to be paid in 2018. Certain transactions resulting from the tolling agreements are accounted for as operating subleases. Total rentals to be received from these operating subleases are approximately $1.1 billion with approximately 4 years remaining on the agreements as of December 31, 2006.

Total rent expense was $242 million in 2006, $226 million in 2005 and $206 million in 2004. Rent expense at Power, primarily related to the tolling agreement, was $175 million (including $11 million of contingent rentals) in 2006 and $161 million (including ($1) million of contingent rentals) in 2005. Power s rent expense was offset by approximately $264 million (including $8 million of contingent rental income) in 2006 and $172 million (including $7 million of contingent rental income) in 2005 resulting from sales and other transactions made possible by the tolling agreement. Contingent rentals are primarily based on utilization of the leased property or changes in the capacity and availability of the power generating facility.

Note 12. Stockholders Equity

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 approximately $220.2 million of the debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest.

We maintain a Stockholder Rights Plan, as amended and restated on September 21, 2004, 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 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

The Williams Companies, Inc. 2002 Incentive Plan (the Plan) was approved by stockholders on May 16, 2002, and amended and restated on May 15, 2003, and January 23, 2004. The Plan provides for common-stock-based awards to both employees and nonmanagement directors. Upon approval by the stockholders, all prior stock plans were terminated resulting in no further grants being made from those plans. However, awards outstanding in those prior plans remain in those plans with their respective terms and provisions.

The Plan permits the granting of various types of awards including, but not limited to, stock options and restricted stock units. Restricted stock units represent deferred share awards subject to time and/or performance-based vesting requirements. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets being achieved. At December 31, 2006, 41.7 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 20 million shares were available for future grants. At December 31, 2005, 45 million shares of our common stock were reserved for issuance, of which 21.6 million were available for future grants.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2006.

Stock Options	Options (Millions)	Weighted-Average Exercise Price	Aggregate Intrinsic Value (Millions)
Outstanding at December 31, 2005	20.4	$ 16.63	
Granted	1.2	$ 21.66	
Exercised	(2.9)	$ 11.72	$ 36.4
Cancelled	(1.0)	$ 32.05	
Outstanding at December 31, 2006	17.7	$ 16.96	$ 198.7
Exercisable at December 31, 2006	13.2	$ 16.90	$ 157.9

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005, and 2004 was $36.4 million, $42.2 million, and $42.4 million, respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2006.

	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Options (Millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)
$2.27 to $10.00	8.4	$ 7.05	5.9	7.1	$ 6.52	5.7
$10.38 to $16.40	.9	$ 15.43	4.5	.9	$ 15.49	4.5

$17.10 to $31.58	5.4	$ 21.22	6.9	2.2	$ 22.81	4.7
$33.51 to $42.29	3.0	$ 37.59	1.7	3.0	$ 37.59	1.7
Total	17.7	$ 16.96	5.4	13.2	$ 16.90	4.5

The estimated fair value at date of grant of options for our common stock granted in 2006, 2005, and 2004, using the Black-Scholes option pricing model, is as follows:

	2006	**2005**	**2004**
Weighted-average grant date fair value of options for our common stock granted during the year	$ 8.36	$ 6.70	$ 4.54
Weighted-average assumptions:			
Dividend yield	1.4%	1.6%	0.4%
Volatility	36.3%	33.3%	50.0%
Risk-free interest rate	4.7%	4.1%	3.3%
Expected life (years)	6.5	6.5	5.0

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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 $34.3 million, $39.4 million and $21.6 million during 2006, 2005 and 2004, respectively. The tax benefit realized from stock options exercised during 2006, 2005 and 2004 was $13.9 million, $14.2 million and $13.7 million, respectively.

Nonvested Restricted Stock Units

Restricted stock units are generally valued at market value on the grant date of the award 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, 2006.

Restricted Stock Units	**Shares (Millions)**	**Weighted-Average Fair Value***
Nonvested at December 31, 2005	2.8	$ 14.60
Granted	1.7	$ 23.39
Forfeited	(.2)	$ 17.76
Vested	(.6)	$ 11.63
Nonvested at December 31, 2006	3.7	$ 20.57

* Performance-based shares are valued at the end-of-period market price. All other shares are valued at the grant-date market price.

Other restricted stock unit information

	2006	**2005**	**2004**
	$ 23.39	$ 19.35	$ 10.54

Weighted-average grant date fair value of restricted stock units granted during the year, per share			
Total fair value of restricted stock units vested during the year ($ s in millions)	$ 14.5	$ 13.7	$ 18.6

Performance-based share awards issued under the Plan represent 34 percent of nonvested restricted stock units outstanding at December 31, 2006. These awards are generally earned at the end of a three-year period based on actual performance against a performance target. Expense associated with these performance-based awards will be recognized in future periods when 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 award amount.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note 14. 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 of cash equivalents reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

Other securities, notes and other noncurrent receivables, structured indemnity settlement obligation, 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. *Other securities* in the table below consists of auction rate securities and held-to-maturity securities and are reported in *other current assets and deferred charges* in the Consolidated Balance Sheet.

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 the prices of similar securities with similar terms and credit ratings. At December 31, 2006 and 2005, approximately 87 percent and 89 percent, respectively, of our long-term debt was publicly traded. We use the expertise of outside investment banking firms to assist with the estimate of the fair value of our long-term debt.

Guarantees: The *guarantees* represented in the table below consists 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 contracts;

Forward contracts;

Swap agreements;

Option contracts.

The fair value of energy derivatives is determined based on the nature of the underlying transaction and the market in which the transaction is executed. We execute most of these transactions on an organized commodity exchange or in over-the-counter markets in which quoted prices exist for active periods. For contracts with terms that exceed the time period for which actively quoted prices are available, we determine fair value by estimating commodity prices during the illiquid periods utilizing internally developed valuations incorporating information obtained from commodity prices in actively quoted markets, quoted prices in less active markets, prices reflected in current transactions, and other market fundamental analysis.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Carrying amounts and fair values of our financial instruments

Asset (Liability)	2006 Carrying Amount	2006 Fair Value	2005 Carrying Amount	2005 Fair Value
	(Millions)			
Cash and cash equivalents	$ 2,268.6	$ 2,268.6	$ 1,597.2	$ 1,597.2
Restricted cash (current and noncurrent)	126.1	126.1	129.4	129.4
Other securities	103.2	103.2	122.9	122.9
Notes and other noncurrent receivables	3.6	3.6	26.6	26.6
Cost based investments (see Note 3)	51.6	(a)	56.7	(a)
Long-term debt, including current portion (see Note 11)(b)	(8,011.6)	(8,480.0)	(7,710.3)	(8,599.4)
Structured indemnity settlement obligation (see Note 10)	(33.9)	(33.9)	(51.3)	(51.3)
Margin deposits	59.3	59.3	349.2	349.2
Customer margin deposits payable	(128.7)	(128.7)	(320.7)	(320.7)
Guarantees	(41.6)	(34.8)	(43.3)	(43.3)
Net energy derivatives:				
Energy commodity cash flow hedges	365.1	365.1	(5.5)	(5.5)
Other energy derivatives	69.8	69.8	106.9	106.9
Other derivatives(c)	1.5	1.5	.9	.9

(a) These investments are primarily in nonpublicly traded companies for which it is not practicable to estimate fair value.

(b) Excludes capital leases.

(c) Consists of nonenergy cash flow hedges.

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 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 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. These

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contracts are 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 electricity attributable to commodity price risk. Certain of these derivatives have been designated as cash flow hedges under SFAS No. 133.

Our Power segment sells electricity produced by our electric generation facilities, obtained contractually through tolling agreements or obtained through marketplace transactions at different locations throughout the United States. We also buy electricity and capacity to serve our full requirements agreements in the Southeast. To reduce exposure to a decrease in revenues and increase in costs from fluctuations in electricity prices, we enter into fixed-price forward physical sales and purchase contracts and financial option contracts to mitigate the price risk on forecasted electricity sales and purchases.

Our electric generation facilities and tolling agreements require natural gas for the production of electricity. To reduce our exposure to increasing costs of natural gas due to changes in market prices, we enter into natural gas futures contracts, swap agreements, fixed-price forward physical purchases and financial option contracts to mitigate the price risk on anticipated purchases of natural gas.

Power 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, changes in the creditworthiness of counterparties, and the hedging derivative contract having an initial fair value upon designation.

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 hedge price risk by entering into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales and purchases of natural gas. We also enter 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.

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 2006, we reclassified approximately $1 million of net gains 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. Approximately $20 million and $2 million of net gains from hedge ineffectiveness are included in *revenues* in the Consolidated Statement of Income during 2006 and 2005, respectively. For 2006 and 2005, there are no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2006, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to nine years. Based on recorded values at December 31, 2006, approximately $9 million of net gains (net of income tax provision of $6 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, 2006. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in 2007 will likely differ from these values. These gains or losses will offset net losses or gains that

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Power elected hedge accounting for certain of its nontrading derivatives in the fourth quarter of 2004 after our Board decided in September 2004 to retain the Power business. Before this election, net changes in the fair value of these derivatives were recognized as revenues in the Consolidated Statement of Income.

Other energy derivatives

Our Power segment has 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 Power s future cash flows on an economic basis.

In addition, our Exploration & Production segment enters into natural gas basis swap agreements that are not designated in a hedging relationship under SFAS No. 133. The fair value of these contracts is approximately $22 million as of December 31, 2006.

Other energy-related contracts

We also hold significant nonderivative energy-related contracts in our Power portfolios. 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 15), we have issued guarantees and other similar arrangements with off-balance sheet risk as discussed below.

In connection with agreements executed prior to our acquisition of Transco to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which 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, Power, 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 substantially exceed the minimum purchase price.

We are required by certain foreign 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 domestic taxes required to be paid

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by the foreign 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.

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 $46 million at December 31, 2006, and $47 million at December 31, 2005. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $41 million at December 31, 2006.

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 consist of high-quality securities placed with various major financial institutions with credit ratings at or above BBB by Standard & Poor s or Baa1 by Moody s Investors Service.

Accounts and notes receivable

The following table summarizes concentration of receivables, net of allowances, by product or service at December 31, 2006 and 2005:

	2006	2005
	(Millions)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$ 894.7	$ 1,142.6
Sales of power and related services	270.2	394.5

Interest	38.6	32.4
Other	9.4	44.3
Total	$ 1,212.9	$ 1,613.8

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. Customers for power include the California Independent System Operator (ISO), the California Department of Water Resources, and other power marketers and utilities located throughout the United States. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

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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. 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.

The concentration of counterparties within the energy and energy trading industry impacts our overall exposure to credit risk in that these counterparties are similarly influenced by changes in the economy and regulatory issues. Additional collateral support could include the following:

Letters of credit;

Payment under margin agreements;

Guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts as of December 31, 2006, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 248.0	$ 249.9
Energy marketers and traders	412.7	1,784.3
Financial institutions	2,219.4	2,219.4
Other	23.3	29.8
	$ 2,903.4	4,283.4
Credit reserves		(20.3)
Gross credit exposure from derivatives		$ 4,263.1

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, 2006, is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 120.4	$ 120.5
Energy marketers and traders	209.0	455.4
Financial institutions	325.5	325.5
Other	20.4	20.4
	$ 675.3	921.8
Credit reserves		(20.3)
Net credit exposure from derivatives		$ 901.5

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

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We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, parent company guarantees, and property interests, as investment grade.

Revenues

In 2006, 2005 and 2004, there were no customers for which our sales exceeded 10 percent of our consolidated revenues.

Note 15. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $2 million for potential refunds as of December 31, 2006.

Issues Resulting From California Energy Crisis

Subsidiaries of our Power segment are 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 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 December 19, 2006 Ninth Circuit Court of Appeals decision, certain contracts that Power entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which Power sold electricity, totaled approximately $89 million in revenue. While Power is not a party to the cases involved in the appellate court decision, the buyer of electricity from Power is a party to the cases and claims that Power must refund to the buyer any loss it suffers due to the decision and the FERC s reconsideration of the contract terms at issue in the decision.

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 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. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $31 million at December 31, 2006. Collection of the interest 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 proceeding, including the refund period, were made to the Ninth Circuit Court of Appeals. On August 2, 2006, the Ninth Circuit issued its order that largely upheld the FERC s prior rulings, but it expanded the types of transactions that were made subject to refund. Because of our settlement, we do not expect this decision will have a material impact on us. No final refund calculation, however, has been made, and certain aspects of the refund calculation process remain unclear and prevent that final refund calculation. As part of the State Settlement, an additional $45 million, previously accrued, remains to be paid

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to the California Attorney General (or his designee) over the next three years, with the final payment of $15 million due on January 1, 2010.

Reporting of Natural Gas-Related Information to Trade Publications

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. In 2002, we received a subpoena from a federal grand jury in northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We have completed our response to the subpoena. Three former traders with Power have pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. One former trader has pled not guilty. On February 21, 2006, we entered into a deferred prosecution agreement with the Department of Justice (DOJ) that is intended to resolve this matter. The agreement obligated us to pay a total of $50 million, of which $20 million was paid in March 2006. The remaining $30 million has been paid in February 2007. Absent a breach, the agreement will expire 15 months from the date of execution of the agreement and no further action will be taken by the DOJ.

Civil suits based on allegations of manipulating the gas indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- Class action litigation in federal court in Nevada alleging that we manipulated gas prices for direct purchasers of gas in California. We have reached settlement of this matter for $2.4 million. Legal documents will be filed with the court and the settlement is subject to court approval.

- Class action litigation in state court in California alleging that we manipulated prices for indirect purchasers of gas in California. On December 11, 2006, the court granted final approval of our settlement of this matter for $15.6 million.

- State court in California on behalf of certain individual gas users.

- Class action litigation in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. On February 2, 2007, the Tennessee court dismissed the case before it because the claims could only be asserted at the FERC.

Earlier this year, we settled a case for $9.15 million in Federal court in New York based on an allegation of manipulation of the NYMEX gas market. It is reasonably possible that additional amounts may be necessary to resolve the remaining outstanding litigation in this area, the amount of which cannot be reasonably estimated at this time.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transco s 2001 general rate case which, among other things, rejected the recovery of the costs of Transco s Mobile Bay expansion project from its shippers on a rolled-in basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In March 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge s decision and accepted Transco s proposal for rolled-in rates. Power holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Power could have been subject to surcharges of approximately $111 million, including interest, through December 31, 2006, in addition to increased costs going forward. Certain parties have filed appeals in federal court seeking to have the FERC s ruling on the rolled-in rates overturned.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Enron Bankruptcy

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively Enron) related to its bankruptcy filed in December 2001. In 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. In 2003, Enron filed objections to these claims. We have resolved Enron s objections, subject to court approval. Pursuant to the sales agreement, the purchaser of the claims has demanded repayment of the purchase price for the reduced portions of the claims. In January 2007, we entered into an agreement-in-principle with the purchaser to settle any potential repayment obligations.

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 programs 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, 2006, we had accrued liabilities of $6 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.

Beginning in the mid-1980 s, 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. Currently, Northwest Pipeline is assessing the actions needed for the sites to comply with Washington s current environmental standards. At December 31, 2006, we have accrued liabilities totaling approximately $5 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At December 31, 2006, we have accrued liabilities totaling approximately $7 million for these costs.

In August 2005, our subsidiary, Williams Production RMT Company, voluntarily disclosed to the Colorado Department of Public Health and Environment (CDPHE) two air permit violations. We have reached an agreement in principle with the CDPHE in which we agree to pay a $500,000 penalty and conduct a supplemental environmental project. A definitive agreement will be finalized soon.

In March 2006, the CDPHE issued a notice of violation (NOV) to Williams Production RMT Company related to our operating permit for the Rulison oil separation and evaporation facility. On April 12, 2006, we met with the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

CDPHE to discuss the allegations contained in the NOV. In May 2006, we provided additional information to the agency regarding the emission estimates for operations from 1997 through 2003 and applied for updated permits.

In July 2006, the CDPHE issued an NOV to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn Gas Plants in Garfield County, Colorado. In September 2006, we met with the CDPHE to discuss the allegations contained in the NOV, and in October 2006, we provided additional requested information to the agency.

In August 2006, the CDPHE issued a NOV to Williams Production RMT Company related to our Grand Valley Oil Separation and Evaporation Facility located in Garfield County, Colorado in which the CDPHE alleged that we failed to obtain a construction permit and to comply with certain provisions of our existing permit. In September, 2006, we met with the CDPHE, and in October 2006, we provided additional requested information to the agency.

In July 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. In March 2004, the DOJ invited the new owner of Williams Energy Partners and Magellan Midstream Partners, L.P. (Magellan) to enter into negotiations regarding alleged violations of the Clean Water Act. With the exception of four minor release events that underwent earlier cleanup operation under state enforcement actions, our environmental indemnification obligations to Magellan were released in a 2004 buyout. We do not expect further enforcement action with respect to the four release events or two 2006 spills at our Colorado and Wyoming facilities after providing additional requested information to the DOJ.

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, 2006, we have accrued liabilities of approximately $9 million for such excess costs.

Other

At December 31, 2006, we have accrued environmental liabilities totaling approximately $25 million related primarily to our:

- Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;

Discontinued petroleum refining facilities;

Former exploration and production and mining operations.

These costs include certain conditions at specified locations related primarily to soil and groundwater contamination and any penalty assessed on Williams Refining & Marketing, L.L.C. (Williams Refining) associated with noncompliance with the EPA s National Emission Standards for Hazardous Air Pollutants (NESHAP). In 2002, Williams Refining submitted a self-disclosure letter to the EPA indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining s Memphis refinery. Also in 2002, the EPA conducted an all-

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

media audit of the Memphis refinery. In 2004, Williams Refining and the new owner of the Memphis refinery met with the EPA and the DOJ to discuss alleged violations and proposed penalties due to noncompliance issues identified in the report, including the benzene NESHAP issue. In July and August 2006, we finalized our agreements that resolved both the government s claims against us for alleged violations and an indemnity dispute with the purchaser in connection with our 2003 sale of the Memphis refinery. We have paid the required settlement amounts to the purchaser, and our payment to the government awaits the filing of the settlement with the court.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, waste) at three facilities: Geismar, Sorrento, and Chalmette, Louisiana. The audit revealed numerous infractions of Louisiana environmental regulations and resulted in a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ). No specific penalty amount was assessed. Instead, LDEQ was required by Louisiana law to demand a profit and loss statement to determine the financial benefit obtained by noncompliance and to assess a penalty accordingly. Gulf Liquids offered $91,500 as a single, final, global multi-media settlement. Subsequent negotiations have resulted in a revised offer of $109,000, which LDEQ is currently reviewing.

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 on April 1, 2005. We are awaiting a decision from the court.

Grynberg

In 1998, the 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 was declining to intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District

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Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg s measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg s royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

On August 6, 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 the state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the BTU heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1.4 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in January 2005, denying liability for the damages claimed. Trial in this case was originally set for May 2006, but the parties have negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case.

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 an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. Other suits alleged similar causes of action related to a public offering in early January 2002 known as the FELINE PACS offering. These cases were also filed in 2002 against us, certain corporate officers, all members of our board of directors and all of the offerings underwriters. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims related to Power. On June 13, 2006, we announced that we had reached an agreement-in-principle to settle the claims of our securities holders for a total payment of $290 million. On October 4, 2006, the court granted preliminary approval of the settlement. On November 3, 2006, we paid into escrow approximately $145 million in cash to fund the settlement, and the balance of the total settlement amount was funded by our insurers. On February 9, 2007, the court gave its final approval to the settlement. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

Litigation with the WilTel equity holders continues but the trial has been stayed pending decisions on various motions for summary judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement or as a result of trial will not likely be covered by insurance, as our insurance coverage has been fully utilized by the settlement described above. The extent of the obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure materially exceeds amounts accrued for this matter.

Derivative shareholder suits have been filed in state court in Oklahoma all based on similar allegations. The state court approved motions to consolidate and to stay these Oklahoma suits pending action by the federal court in

THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the shareholder suits. On December 23, 2006, our insurer paid $1.2 million on our behalf to reimburse the plaintiffs attorneys fees and expenses which concluded the settlement of these suits. We previously implemented certain corporate governance and internal control enhancements that we agreed to under the court-approved settlement agreement.

Federal income tax litigation

One of our wholly-owned subsidiaries, Transco Coal Gas Company, was engaged in a dispute with the Internal Revenue Service (IRS) regarding the recapture of certain income tax credits associated with the construction of a coal gasification plant in North Dakota by Great Plains Gasification Associates, in which Transco Coal Gas Company was a partner. This case has been resolved. (See Note 5.)

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), is actively 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. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. Due to the sale of WAPI s interests on March 31, 2004, no future Quality Bank liability will accrue but we are responsible for any liability that existed as of that date including potential liability for any retroactive payments that might be awarded in these proceedings for the period prior to March 31, 2004. In the third quarter of 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. In third-quarter 2004, we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable.

The FERC and the RCA completed their reviews of the initial decisions and in 2005 issued substantially similar orders generally affirming the initial decisions. On June 1, 2006, the FERC, after two sets of rehearing requests, entered its final order (FERC Final Order). During this administrative rehearing process all other appeals of the initial decisions were stayed including ExxonMobil s appeal to the D.C. Circuit Court of Appeals asserting that the FERC s reliance on the Highway Reauthorization Act as the basis for limiting the retroactive effect violates, among other things, the separation of powers under the U.S. Constitution by interfering with the FERC s independent decision-making role. ExxonMobil filed a similar appeal in the Alaska Superior Court. We also appealed the FERC s order to the extent of its ruling on the West Coast Heavy Distillate component.

The Quality Bank Administrator issued his interpretations of the payment obligations under the FERC Final Order, and we and others filed exceptions to these instructions with the FERC. We expect the FERC s ruling on these payment instruction exceptions later in the first quarter of 2007. Once the FERC rules, the Administrator will invoice us for amounts due, and we will be required to pay the invoiced amounts, subject to the outcome of the appeals of the FERC Final Order. We estimate that our net obligation could be as much as $116 million. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

Redondo Beach taxes

On February 5, 2005, Power received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and Power, from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found Power jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$21 million. Both we and AES Redondo Beach filed notices of appeal that were heard at the city level. On December 13, 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming our utility user tax liability and reversing AES Redondo s liability because the officer ruled that AES Redondo is an exempt public utility. Even though we appealed this decision to the Los Angeles Superior Court, we may be required to pay the full amount of any final assessment prior to the resolution of this state court appeal. Despite the city hearing officer s unfavorable decision and the potential payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The City s current assessment of our liability (for the periods from 1998 through September 2006) is approximately $69 million (inclusive of interest and penalties). We have protested all these assessments and requested hearings on them. We and AES Redondo have also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. We believe that under our tolling agreement related to the Redondo Beach generating facility, AES Redondo Beach is responsible for taxes of the nature asserted by the city; however, AES Redondo Beach has notified us that it does not agree.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay 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. Gulsby and Gulsby-Bay defaulted on the construction contracts. In the fall of 2001, the contractors, sureties, and Gulf Liquids filed multiple cases in Louisiana and Texas. In January 2002, NAICO added Gulf Liquids co-venturer Power to the suits as a third-party defendant. Gulf Liquids asserted claims against the contractors and sureties for, among other things, breach of contract requesting contractual and consequential damages from $40 million to $80 million, any of which is subject to a sharing arrangement with XL Insurance Company.

At the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual damages verdict against Power and Gulf Liquids on July 31, 2006 and its related punitive damages verdict on August 1, 2006. The court is not expected to enter any judgment until the second or third quarter of 2007. Based on our interpretation of the jury verdicts, we have estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $22 million, all of which have been accrued as of December 31, 2006. In addition, it is reasonably possible that any ultimate judgment may include additional amounts of approximately $199 million in excess of our accrual, which primarily represents our estimate of potential punitive damage exposure under Texas law.

Hurricane lawsuits

We were named as a defendant in two class action petitions for damages filed in federal court in Louisiana in September and October 2005 arising from hurricanes that struck Louisiana in 2005. The class action plaintiffs, purporting to represent persons, businesses and entities in the State of Louisiana who have suffered damage as a result of the winds and storm surge from the hurricanes, allege that the operating activities of the two sub-classes of defendants, which are all oil and gas pipelines (including Transco) that dredged pipeline canals or installed pipelines in the marshes of south Louisiana and all oil and gas exploration and production companies which drilled for oil and gas or dredged canals in the marshes of south Louisiana, have altered marshland ecology and caused marshland destruction which otherwise would have averted all or almost all of the destruction and loss of life caused by the hurricanes. Plaintiffs requested that the court allow the lawsuits to proceed as class actions and sought legal and equitable relief in an unspecified amount. In September 2006, the court granted our and the other defendants joint motion to dismiss the class action petitions on various grounds. In August 2006, an additional class action case containing substantially identical allegations was filed against the same defendants, including Transco. This case was dismissed on November 30, 2006.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Wyoming severance taxes

The Wyoming Department of Audit (DOA) audited the severance tax reporting for our subsidiary Williams Production RMT Company for the production years 2000 through 2002. In August 2006, the DOA assessed additional severance tax and interest for those periods of approximately $3 million. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes, which is estimated to result in additional taxes of approximately $2 million, including interest. We dispute the DOA s interpretation of the statutory obligation and have appealed this assessment to the Wyoming State Board of Equalization. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $21 million to $23 million in taxes and interest from January 1, 2003, through December 31, 2006.

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 agreed to stay this action in order to participate in a mediation to be scheduled.

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.

We sold a natural gas liquids pipeline system in 2002, and in July 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks an unspecified amount of damages and our specific performance under certain guarantees. On September 1, 2006, we filed our answer to the purchaser s complaint denying all liability. We anticipate that the trial will occur in the fourth quarter 2007, and our prior suit filed against the purchaser in Delaware state court has been stayed pending resolution of the Texas case.

At December 31, 2006, 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 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 materially adverse effect upon our future financial position.

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Commitments

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At December 31, 2006, Power s estimated committed payments under these contracts range from approximately $406 million to $424 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next sixteen years are approximately $5.5 billion. Included in the $5.5 billion is a $1.9 billion contract that is accounted for as an operating lease. (See Leases-Lessee in Note 11.) Total payments made under these contracts during 2006, 2005, and 2004 were $409 million, $403 million, and $402 million, respectively.

Commitments for construction and acquisition of property, plant and equipment are approximately $406 million at December 31, 2006.

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Note 16. 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	Unrealized Appreciation (Depreciation) On Securities	Foreign Currency Translation	Minimum Pension Liability	Prior Service Cost	Net Actuarial Loss	Prior Service Cost	Net Actuarial Gain	Total
					(Millions)				
Balance at December 31, 2003	$ (165.6)	$ (1.9)	$ 53.1	$ (6.6)	$	$	$	$	$ (121.0)
2004 Change:									
Pre-income tax amount	(460.9)	(2.4)	15.8	3.0					(444.5)
Income tax benefit (provision)	176.5	.9		(1.2)					176.2
Net reclassification into earnings of derivative instrument losses (net of a $87.8 million income tax benefit)	141.7								141.7
Realized losses on securities reclassified into earnings (net of a $2.1 million income tax benefit)		3.4							3.4
	(142.7)	1.9	15.8	1.8					(123.2)

Balance at December 31, 2004	(308.3)	68.9	(4.8)					(244.2)
2005 Change:								
Pre-income tax amount	(395.5)	11.4	.6					(383.5)
Income tax benefit (provision)	151.3		(.2)					151.1
Net reclassification into earnings of derivative instrument losses (net of a $110.8 million income tax benefit)	178.8							178.8
	(65.4)	11.4	.4					(53.6)
Balance at December 31, 2005	(373.7)	80.3	(4.4)					(297.8)
2006 Change:								
Pre-income tax amount	423.2	(4.7)	(1.3)					417.2
Income tax benefit (provision)	(161.8)		.4					(161.4)
Net reclassification into earnings of derivative instrument losses (net of a $82.3 million income tax benefit)	132.8							132.8
	394.2	(4.7)	(.9)					388.6
Adjustment to initially apply SFAS No. 158:								
Pre-income tax amount			8.4	(5.7)	(243.2)*	(6.7)	(7.8)	(255.0)
			(3.1)	2.2	92.5	2.6	9.9	104.1

Income tax benefit (provision)				5.3	(3.5)	(150.7)	(4.1)	2.1	(150.9)
Balance at December 31, 2006	$ 20.5	$	$ 75.6	$	$ (3.5)	$ (150.7)	$ (4.1)	$ 2.1	$ (60.1)

* Includes $0.8 million for the Net Actuarial Loss of an equity method investee.

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Available-for-Sale Securities

During 2004, we received proceeds totaling $851.4 million from the sale and maturity of available-for-sale securities. We realized losses of $5.5 million from these transactions.

Note 17. 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 partnership, Williams Partners L.P., is consolidated within our Midstream segment. (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, depreciation, depletion and amortization, equity earnings (losses)* and *income (loss) from investments* including impairments related to investments accounted for under the equity method. 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.

During 2004, Power was party to intercompany interest rate swaps with the corporate parent, the effect of which is included in Power s *segment revenues* and *segment profit (loss)* as shown in the reconciliation within the following tables. We terminated these interest-rate derivatives in the fourth quarter of 2004.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with the unrelated third parties. External revenues of our Exploration & Production segment includes third-party oil and gas sales, 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:			
2006	$ 11,418.3	$ 394.6	$ 11,812.9
2005	12,258.3	325.3	12,583.6
2004	12,167.8	293.5	12,461.3
Long-lived assets:			

2006	$ 14,510.4	$ 681.7	$ 15,192.1
2005	12,692.7	739.8	13,432.5
2004	12,149.0	762.0	12,911.0

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.

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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	Power	Other	Eliminations	Total
				(Millions)			
2006							
Segment revenues:							
External	$ (189.9)	$ 1,335.6	$ 4,071.1	$ 6,585.9	$ 10.2	$	$ 11,812.9
Internal	1,677.5	12.1	53.6	876.5	16.3	(2,636.0)	
Total revenues	$ 1,487.6	$ 1,347.7	$ 4,124.7	$ 7,462.4	$ 26.5	$ (2,636.0)	$ 11,812.9
Segment profit (loss)	$ 551.5	$ 467.4	$ 658.3	$ (210.8)	$ 1.9	$	$ 1,468.3
Less equity earnings	21.8	37.1	27.0	13.0			98.9
Segment operating income (loss)	$ 529.7	$ 430.3	$ 631.3	$ (223.8)	$ 1.9	$	1,369.4
General corporate expenses							(132.1)
Securities litigation settlement and related costs							(167.3)
Consolidated operating income							$ 1,070.0
Other financial information:							
Additions to long-lived assets	$ 1,495.7	$ 913.2	$ 279.4	$ 1.1	$ 18.1	$	$ 2,707.5
Depreciation, depletion & amortization	$ 360.2	$ 281.7	$ 201.2	$ 10.7	$ 11.7	$	$ 865.5
2005							
Segment revenues:							
External	$ (201.6)	$ 1,395.0	$ 3,187.6	$ 8,192.5	$ 10.1	$	$ 12,583.6

Internal	1,470.7	17.8	45.1	901.4	17.1	(2,452.1)	
Total revenues	$ 1,269.1	$ 1,412.8	$ 3,232.7	$ 9,093.9	$ 27.2	$ (2,452.1)	$ 12,583.6
Segment profit (loss)	$ 587.2	$ 585.8	$ 471.2	$ (256.7)	$ (105.0)	$	$ 1,282.5
Less:							
Equity earnings (losses)	18.8	43.6	23.6	3.1	(23.5)		65.6
Income (loss) from investments			1.0	(23.0)	(87.1)		(109.1)
Segment operating income (loss)	$ 568.4	$ 542.2	$ 446.6	$ (236.8)	$ 5.6	$	1,326.0
General corporate expenses							(145.5)
Securities litigation settlement and related costs							(9.4)
Consolidated operating income							$ 1,171.1
Other financial information:							
Additions to long-lived assets	$ 794.7	$ 420.2	$ 133.2	$ 5.9	$ 4.7	$	$ 1,358.7
Depreciation, depletion & amortization	$ 254.2	$ 267.3	$ 192.0	$ 14.9	$ 11.6	$	$ 740.0
2004							
Segment revenues:							
External	$ (84.0)	$ 1,345.0	$ 2,844.7	$ 8,346.2	$ 9.4	$	$ 12,461.3
Internal	861.6	17.3	37.9	912.5	23.4	(1,852.7)	
Total segment revenues	777.6	1,362.3	2,882.6	9,258.7	32.8	(1,852.7)	12,461.3
Less intercompany interest rate swap loss				(13.7)		13.7	
Total revenues	$ 777.6	$ 1,362.3	$ 2,882.6	$ 9,272.4	$ 32.8	$ (1,866.4)	$ 12,461.3
Segment profit (loss)	$ 235.8	$ 585.8	$ 549.7	$ 76.7	$ (41.6)	$	$ 1,406.4
Less:							
Equity earnings (losses)	11.9	29.2	14.6	3.9	(9.7)		49.9
Loss from investments		(1.0)	(17.1)		(17.4)		(35.5)
				(13.7)			(13.7)

Intercompany interest rate swap loss							
Segment operating income (loss)	$ 223.9	$ 557.6	$ 552.2	$ 86.5	$ (14.5)	$	1,405.7
General corporate expenses							(119.8)
Consolidated operating income							$ 1,285.9
Other financial information:							
Additions to long-lived assets	$ 445.4	$ 300.1	$ 91.3	$ 1.0	$ 6.0	$	$ 843.8
Depreciation, depletion & amortization	$ 192.3	$ 264.4	$ 178.4	$ 20.1	$ 13.3	$	$ 668.5

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THE WILLIAMS COMPANIES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Total Assets			Equity Method Investments		
	December 31, 2006	December 31, 2005	December 31, 2004	December 31, 2006	December 31, 2005	December 31, 2004
	(Millions)					
Exploration & Production(1)	$ 7,850.9	$ 8,672.0	$ 5,576.4	$ 58.8	$ 58.4	$ 44.9
Gas Pipeline	8,331.7	7,581.0	7,651.8	432.4	439.1	769.5
Midstream Gas & Liquids	5,483.8	4,677.7	4,211.7	304.1	314.2	273.3
Power(2)	6,884.8	14,989.2	8,204.1	19.1	19.2	45.6
Other	4,224.6	3,942.7	3,597.6		.2	113.2
Eliminations(3)	(7,373.4)	(10,420.0)	(5,248.6)			
Total Assets	$ 25,402.4	$ 29,442.6	$ 23,993.0	$ 814.4	$ 831.1	$ 1,246.5

(1) The 2006 decrease and 2005 increase in Exploration & Production s total assets are due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing derivative contracts. Exploration & Production s derivatives are primarily comprised of intercompany transactions with the Power segment.

(2) The 2006 decrease and 2005 increase in Power s total assets are due primarily to the fluctuations in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Power s derivative assets are substantially offset by their derivative liabilities.

(3) The 2006 decrease and 2005 increase in Eliminations are due primarily to the fluctuations in the intercompany derivative balances.

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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
2006				
Revenues	$ 3,027.5	$ 2,715.1	$ 3,300.0	$ 2,770.3
Costs and operating expenses	2,588.7	2,273.8	2,822.4	2,288.7
Income (loss) from continuing operations	131.1	(63.9)	110.1	155.5
Net income (loss)	131.9	(76.0)	106.2	146.4
Basic earnings per common share:				
Income (loss) from continuing operations	.22	(.11)	.19	.27
Diluted earnings per common share:				
Income (loss) from continuing operations	.22	(.11)	.19	.25
2005				
Revenues	$ 2,954.0	$ 2,871.2	$ 3,082.3	$ 3,676.1
Costs and operating expenses	2,390.3	2,491.6	2,826.2	3,162.9
Income from continuing operations	202.2	40.7	5.7	68.8
Income before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5
Net income	201.1	41.3	4.4	66.8
Basic earnings per common share:				
Income from continuing operations	.36	.07	.01	.12
Income before cumulative effect of change in accounting principle	.36	.07	.01	.12
Diluted earnings per common share:				
Income from continuing operations	.34	.07	.01	.11
Income before cumulative effect of change in accounting principle	.34	.07	.01	.11

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.

Net income (loss) for fourth quarter 2006 includes a $40 million reduction to the tax provision associated with a favorable U.S. Tax Court ruling, a $7.4 million increase to the tax provision associated with an adjustment to deferred income taxes (see Note 5) and the following pre-tax items:

A $16.4 million impairment of a Venezuelan cost-based investment at Exploration & Production (see Note 3);

A $14.7 million charge associated with an oil purchase contract related to our former Alaska refinery (see Note 2).

Net income (loss) for third quarter 2006 includes the following pre-tax items:

$12.7 million of income due to a reduction of contingent obligations at our former distributive power generation business at Power (see Note 4);

$10.6 million of expense related to an adjustment of an accounts payable accrual at Midstream;

$6 million accrual for a loss contingency related to a former exploration business (see Note 2);

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THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA (Continued)
(Unaudited)

Net income (loss) for second quarter 2006 includes the following pre-tax items:

$160.7 million accrual related to our securities litigation settlement at Other (see Note 15);

$88 million accrual for Gulf Liquids litigation contingency and associated interest expense at Midstream (see Note 4);

$19.2 million accrual for an adverse arbitration award related to our former chemical fertilizer business (see Note 2).

Net income (loss) for the first quarter 2006 includes the following pre-tax items:

$27 million premium and conversion expenses related to the convertible debenture conversion at Other (see Note 12);

$23.7 million gain on sale of certain receivables at Power;

$9 million of income related to the settlement of an international contract dispute at Midstream;

$7 million associated with the reversal of an accrued litigation contingency due to a favorable court ruling and the related accrued interest income at our Gas Pipeline segment.

Net income for fourth quarter 2005 includes a $20.2 million reduction to the tax provision associated with an adjustment to deferred income taxes (see Note 5) and the following pre-tax items:

$68.7 million accrual for litigation contingencies at Power (see Note 4);

$38.1 million impairment of our investment in Longhorn at Other (see Note 3);

$32.1 million charge related to accounting and valuation corrections for certain inventory items at Gas Pipeline (see Note 4);

$23 million impairment of our investment in Aux Sable at Power (see Note 3);

$5.2 million accrual for contingent refund obligations at Gas Pipeline (see Note 4).

Net income for third quarter 2005 includes the following pre-tax items:

$21.7 million gain on sale of certain natural gas properties at Exploration & Production (see Note 4);

$14.2 million of income from the reversal of a liability due to resolution of litigation at Gas Pipeline;

$13.8 million increase in expense related to the settlement of certain insurance coverage issues associated with ERISA and securities litigation at Other.

Net income for second quarter 2005 includes the following pre-tax items:

$49.1 million impairment of our investment in Longhorn at Other (see Note 3);

$17.1 million reduction of expense at Gas Pipeline to correct the overstatement of pension expense in prior periods (see Note 7);

$13.1 million accrual for litigation contingencies at Power (see Note 4);

$8.6 million gain on sale of our remaining interests in Mid-America Pipeline and Seminole Pipeline at Midstream.

Net income for first quarter 2005 includes the following pre-tax items:

$13.1 million of income due to the reversal of certain prior period accruals at Gas Pipeline;

$7.9 million gain on sale of certain natural gas properties at Exploration & Production (see Note 4).

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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 4.2 percent and 4.3 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, 2006	2005
	(Millions)	
Proved properties	$ 5,026.6	$ 3,870.5
Unproved properties	500.3	503.1
	5,526.9	4,373.6
Accumulated depreciation, depletion and amortization and valuation provisions	(1,259.9)	(937.4)
Net capitalized costs	$ 4,267.0	$ 3,436.2

Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These amounts for 2006 and 2005 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 and related equipment and facilities (including uncompleted development well costs); and successful exploratory wells and related equipment and facilities.

Unproved properties consist primarily of acreage related to probable/possible reserves acquired through the Barrett acquisition in 2001. The balance is unproved exploratory acreage.

Costs Incurred

	For the Year Ended December 31, 2006	2005	2004
		(Millions)	
Acquisition	$ 84.0	$ 45.3	$ 17.2

Exploration	20.2	8.3	4.5
Development	1,172.5	723.1	419.2
	$ 1,276.7	$ 776.7	$ 440.9

Costs incurred include capitalized and expensed items.

Acquisition costs are as follows: The 2006 cost is primarily for additional land and reserve acquisitions in the Fort Worth basin. The 2005 costs primarily consist of a land and reserve acquisition in the Fort Worth basin and an additional land acquisition in the Arkoma basin. The 2004 costs relate to land and reserve acquisitions in the San Juan Basin, Arkoma basin, and the Powder River 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, 2006	2005	2004
		(Millions)	
Revenues:			
Oil and gas revenues	$ 1,237.8	$ 1,072.4	$ 599.9
Other revenues	186.1	143.3	137.3
Total revenues	1,423.9	1,215.7	737.2
Costs:			
Production costs	308.5	230.3	165.4
General & administrative	111.1	79.5	58.3
Exploration expenses	18.4	8.3	4.5
Depreciation, depletion & amortization	351.1	244.7	183.4
(Gains)/Losses on sales of interests in oil and gas properties	(.4)	(30.8)	0.1
Other expenses	136.1	141.1	115.2
Total costs	924.8	673.1	526.9
Results of operations	499.1	542.6	210.3
Provision for income taxes	(174.5)	(216.9)	(81.4)
Exploration and production net income	$ 324.6	$ 325.7	$ 128.9

Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit. Other expenses in 2005 and 2004 include a $6 million and $16 million gain, respectively, on sales of securities associated with a coal seam royalty trust.

Oil and gas revenues consist primarily of natural gas production sold to the Power subsidiary and includes the impact of 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 non-producing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to the Power subsidiary or third party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain non-operating 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 acquisition, exploration and development costs.

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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.

Depreciation, depletion and amortization includes depreciation of support equipment.

Proved Reserves

	2006	2005 (Bcfe)	2004
Proved reserves at beginning of period	3,382	2,986	2,703
Revisions	(113)	(12)	(70)
Purchases	41	28	24
Extensions and discoveries	669	615	521
Production	(277)	(224)	(191)
Sale of minerals in place	(1)	(11)	(1)
Proved reserves at end of period	3,701	3,382	2,986
Proved developed reserves at end of period	1,945	1,643	1,348

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.

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 $4.81, $6.95, and $5.08 per MMcfe at December 31, 2006, 2005, and 2004, 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 $3,070 million of future development costs, $1,041 million, $942 million and $540 million are estimated to be spent in 2007, 2008 and 2009, respectively.

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THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES (Continued)
(Unaudited)

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, 2006	2005
	(Millions)	
Future cash inflows	$ 17,821	$ 23,510
Less:		
Future production costs	5,207	4,441
Future development costs	3,070	2,258
Future income tax provisions	3,350	6,128
Future net cash flows	6,194	10,683
Less 10 percent annual discount for estimated timing of cash flows	3,338	5,402
Standardized measure of discounted future net cash flows	$ 2,856	$ 5,281

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

	2006	2005 (Millions)	2004
Standardized measure of discounted future net cash flows beginning of period	$ 5,281	$ 3,147	$ 3,349
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(1,179)	(1,222)	(835)
Net change in prices and production costs	(4,052)	2,358	(306)
Extensions, discoveries and improved recovery, less estimated future costs	647	1,310	787
Development costs incurred during year	881	723	419
Changes in estimated future development costs	(1,022)	(300)	(696)
Purchase of reserves in place, less estimated future costs	63	78	29
Sales of reserves in place, less estimated future costs	(2)	(31)	(3)
Revisions of previous quantity estimates	(140)	(28)	(90)
Accretion of discount	790	488	286

Net change in income taxes	1,468	(1,272)	182
Other	121	30	25
Net changes	(2,425)	2,134	(202)
Standardized measure of discounted future net cash flows end of period	$ 2,856	$ 5,281	$ 3,147

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THE WILLIAMS COMPANIES, INC.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

		ADDITIONS			
	Beginning Balance	Charged to Cost and Expenses	Other (Millions)	Deductions	Ending Balance
Year ended December 31, 2006:					
Allowance for doubtful accounts accounts and notes receivable(a)	$ 86.6	$ 3.7	$ (65.6)(f)	$ 8.8(c)	$ 15.9
Price-risk management credit reserves(a)	37.0	(6.1)(d)	(10.6)(e)		20.3
Processing plant major maintenance accrual(b)	7.2	1.6		.9	7.9
Year ended December 31, 2005:					
Allowance for doubtful accounts accounts and notes receivable(a)	98.8	3.5		15.7(c)	86.6
Price-risk management credit reserves(a)	26.4	(2.6)(d)	13.2(e)		37.0
Processing plant major maintenance accrual(b)	5.7	1.5			7.2
Year ended December 31, 2004:					
Allowance for doubtful accounts accounts and notes receivable(a)	112.2	(.8)		12.6(c)	98.8
Price-risk management credit reserves(a)	39.8	(12.8)(d)	(.6)(e)		26.4
Processing plant major maintenance accrual(b)	4.1	1.6			5.7

(a) Deducted from related assets.

(b) Included in *accrued liabilities* in 2006 and *other liabilities and deferred income* in 2005 and 2004.

(c) Represents balances written off, reclassifications, and recoveries.

(d) Included in *revenues.*

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

(f) During 2006, $65.6 million in previously reserved Enron receivables were sold.

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

None

Item 9A. *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (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.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our 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.

Management s Report on Internal Control over Financial Reporting

See Management s Report on Internal Control over Financial Reporting set forth in Item 8, Financial Statements and Supplementary Data.

Fourth Quarter 2006 Changes in Internal Control Over Financial Reporting

There have been no changes during the fourth quarter that materially affected, or are reasonably likely to materially affect, our internal control 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 headings Board of Directors Board Committees, Election of Directors, and Principal Accounting Fees and Services in our Proxy Statement prepared for the solicitation of proxies in connection with our Annual Meeting of Stockholders to be held May 17, 2007 (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 in our Proxy Statement, which information in 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 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 Board of Directors, Executive Compensation, Compensation committee interlocks and insider participation, and Compensation committee report in our Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the heading Compensation Committee Report 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 Certain Relationships and Related Transactions and Corporate Governance in our Proxy Statement, which information is incorporated by reference herein.

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

The information regarding our principal accountant fees and services required by Item 9(e) of Schedule 14A will be presented under the heading Principal Accountant Fees and Services in our Proxy Statement, which information is incorporated by reference herein.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) 1 and 2.

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.	Description
3.1*	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3.1 to our Form 10-K filed March 11, 2005).
3.2*	Restated By-laws (filed as Exhibit 3.2 to our Form 8-K filed January 31, 2007).
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4.4*	Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
4.5*	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to our Form 10-K for the fiscal year ended December 31, 2000).
4.6*	

	Sixth Supplemental Indenture dated January 14, 2002, between Williams and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 8-K filed January 23, 2002).
4.7*	Seventh Supplemental Indenture dated March 19, 2002, between The Williams Companies, Inc. as Issuer and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to our Form 10-Q filed May 9, 2002).
4.8*	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc. s our Form 10-Q filed October 18, 1995).

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4.10*	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 as Exhibit 4.4.1 to MAPCO Inc. s Amendment No. 1 to Form S-3 dated February 25, 1997).
4.11*	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).
4.12*	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).
4.13*	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).
4.14*	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 as Exhibit 4(q) to our Form 10-K for the fiscal year ended December 31, 1999).
4.15*	Revised Form of Indenture between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee, with respect to Senior Notes including specimen of 7.55% Senior Notes (filed as Exhibit 4.1 to Barrett Resources Corporation s Amendment No. 2 to our Registration Statement on Form S-3 filed February 10, 1997).
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4.17*	Second Supplemental Indenture dated as of August 2, 2001, among Barrett Resources Corporation, as Issuer, Resources Acquisition Corp., The Williams Companies, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.4 to our Form 10-Q filed November 13, 2001).
4.18*	Third Supplemental Indenture dated as of May 20, 2004 with respect to the Indenture dated as of February 1, 1997 between Barrett Resources Corporation (predecessor-in-interest to Williams Production RMT Company) and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee (filed as Exhibit 99.2 to our Form 8-K filed May 20, 2004).
4.19*	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 as Exhibit 4.2 to our Form 10-Q filed August 12, 2003).
4.20*	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 as Exhibit 4.1 to our Form 8-K filed September 21, 2004.
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4.23*	Senior Indenture, dated as of December 8, 1997, between Northwest Pipeline Corporation and The Chase Manhattan Bank, Trustee with regard to Northwest Pipeline s 6.625% Debentures, due 2007 (filed as Exhibit 4.1 to Northwest Pipeline s Form S-3 filed September 8, 1997)
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4.27*	Senior Indenture dated as of January 16, 1998 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-3 dated September 8, 1997).
4.28*	Indenture dated as of August 27, 2001 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-4 dated November 8, 2001).
4.29*	Indenture dated as of July 3, 2002 between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to The Williams Companies Inc. s Form 10-Q for the quarterly period ended June 30, 2002).
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4.32*	Indenture dated June 20, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and JPMorgan Chase Bank, N.A. (filed as Exhibit 4.1 to Williams Partners L.P. Form 8-K filed June 20, 2006).
4.33*	Indenture dated December 13, 2006, by and among Williams Partners L.P., Williams Partners Finance Corporation and The Bank of New York (filed as Exhibit 4.1 to Williams Partners L.P. filed December 19, 2006).
10.1*	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to our Form 10-K for the fiscal year ended December 31, 1987).
10.2*	First Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of April 1, 1988 (filed as Exhibit 10.2 to our Form 10-K for the fiscal year ended December 31, 2003).
10.3*	Second Amendment to The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 2002 and January 1, 2003 (filed as Exhibit 10.3 to our Form 10-K filed March, 11, 2005).
10.4*	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to our Form 10-K for the fiscal year ended December 31, 1995).
10.5*	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.6*	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
10.7	The Williams Companies, Inc. 2001 Stock Plan.
10.8	The Williams Companies, Inc. 2002 Incentive Plan for Non-Employee Director Stock Option Agreement.

10.9*	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to our Form 10-K for the year ended December 31, 1986).
10.10*	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to our Form 10-K for the fiscal year ended December 31, 1998).

Exhibit No.	Description
10.11*	Form of 2004 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 10.12 to our Form 10-K filed March 11, 2005).
10.12*	Form of 2004 Performance-Based Deferred Stock Agreement among Williams and executive officers filed as Exhibit 10.13 to our Form 10-K filed March 11, 2005).
10.13*	Form of Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 2, 2005).
10.14*	Form of 2005 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 2, 2005).
10.15*	Form of 2005 Performance-Based Deferred Stock Agreement among Williams and executive officers.(filed as Exhibit 99.3 to our Form 8-K filed March 2, 2005).
10.16*	Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).
10.17*	Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).
10.18*	Form of 2006 Performance-Based Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Form 8-K filed March 7, 2006).
10.19*	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.20*	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed as Exhibit 10.1 to our Form 10-Q filed on August 5, 2004).
10.21*	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.22*	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing & Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.23*	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated Effective October 28, 2003.
10.24*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003.
10.25*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004.
10.26*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005.
10.27*	U.S. $500,000,000 Term Loan Agreement among Williams Production Holdings LLC, Williams Production RMT Company, as Borrower, the Several Lenders from time to time parties thereto, Lehman Brothers Inc. and Banc of America Securities LLC as Joint Lead Arrangers, Citigroup USA, Inc. and JPMorgan Chase Bank, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.1 to our Form 10-Q filed August 12, 2003).
10.28*	The First Amendment to the Term Loan Agreement dated February 25, 2004, between Williams Production Holdings, LLC, Williams Production RMT Company, as Borrower, the several financial institutions as lenders and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.3 to our Form 10-Q filed May 6, 2004).
10.29*	Guarantee and Collateral Agreement made by Williams Production Holdings LLC, Williams Production RMT Company and certain of its Subsidiaries in favor of Lehman Commercial Paper Inc. as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.2 to our Form 10-Q filed August 12, 2003).

10.30*	U.S. $1,275,000,000 Amended and Restated Credit Agreement Dated as of May 20, 2005 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, Williams Partners L.P., as Borrowers, Citicorp USA, Inc., As Administrative Agent and Collateral Agent, Citibank, N.A. Bank of America, N.A. as Issuing Banks and The Banks Named Herein as Banks (filed as Exhibit 1.1 to our Form 8-K filed May 26, 2005).

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Exhibit No.	Description
10.31*	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 as Exhibit 10.1 to our form 8-K filed May 1, 2006).
10.32*	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 as Exhibit 10.3 to our Form 8-K filed on January 26, 2005).
10.33*	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 as Exhibit 10.4 to our Form 8-K filed on January 26, 2005).
10.34*	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 as Exhibit 10.3 to our Form 8-K filed on September 26, 2005).
10.35*	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 as Exhibit 10.3 to our Form 8-K filed on September 26, 2005).
10.36*	Assumption Agreement dated June 17, 2003 by and between The Williams Companies, Inc. and WEG Acquisitions, L.P. (filed as Exhibit 10.10 to our Form 10-Q filed August 12, 2003).
10.37*	Agreement for the Release of Certain Indemnification Obligations dated as of May 26, 2004 by and among Magellan Midstream Holdings, L.P., Magellan G.P. LLC and Magellan Midstream Partners, L.P., on the one hand, and The Williams Companies, Inc., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and Williams GP LLC, on the other hand (filed as Exhibit 10.6 to our Form 10-Q filed August 5, 2004).
10.38*	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed as Exhibit 10.2 to our Form 10-Q filed August 5, 2004).
10.39*	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 as Exhibit 10.3 to our Form 10-Q filed August 5, 2004).
10.40*	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 (incorporated by reference to Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 1-32599) filed on November 21, 2006) filed as Exhibit 2.1 to our Form 8-K filed November 22, 2006).
10.41	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.
12	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.

14*	Code of Ethics (filed as Exhibit 14 to Form 10-K for the fiscal year ended December 31, 2003).
20*	Definitive Proxy Statement of Williams for 2007 (to be filed with the Securities and Exchange Commission on or before April , 2007).
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.

Exhibit No.	Description
24	Power of Attorney together with certified resolution.
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.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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SIGNATURES

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

The Williams Companies, Inc.
(Registrant)

By: /s/ Brian K. Shore
Brian K. Shore
Attorney-in-fact

Date: February 28, 2007

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

Signature	Title	Date
/s/ Steven J. Malcolm* Steven J. Malcolm*	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 28, 2007
/s/ Donald R. Chappel* Donald R. Chappel*	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
/s/ Ted T. Timmermans* Ted T. Timmermans*	Controller (Principal Accounting Officer)	February 28, 2007
/s/ Kathleen B. Cooper* Kathleen B. Cooper*	Director	February 28, 2007
/s/ Irl F. Engelhardt* Irl F. Engelhardt*	Director	February 28, 2007
/s/ William R. Granberry* William R. Granberry*	Director	February 28, 2007

/s/ William E. Green*	Director	February 28, 2007
William E. Green*		
/s/ Juanita H. Hinshaw*	Director	February 28, 2007
Juanita H. Hinshaw*		
/s/ W.R. Howell*	Director	February 28, 2007
W.R. Howell*		
/s/ Charles M. Lillis*	Director	February 28, 2007
Charles M. Lillis*		
/s/ George A. Lorch*	Director	February 28, 2007
George A. Lorch*		

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Signature	Title	Date
/s/ William G. Lowrie*	Director	February 28, 2007
William G. Lowrie*		
/s/ Frank T. Macinnis*	Director	February 28, 2007
Frank T. Macinnis*		
/s/ Janice D. Stoney*	Director	February 28, 2007
Janice D. Stoney*		

*By: /s/ Brian K. Shore

Brian K. Shore
Attorney-in-Fact

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10.4*	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to our Form 10-K for the fiscal year ended December 31, 1995).
10.5*	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to our Proxy Statement dated March 27, 1996).
10.6*	The Williams Companies, Inc. 1996 Stock Plan for Non-employee Directors (filed as Exhibit B to our Proxy Statement dated March 27, 1996).
10.7	The Williams Companies, Inc. 2001 Stock Plan.
10.8	The Williams Companies, Inc. 2002 Incentive Plan for Non-Employee Director Stock Option Agreement.
10.9*	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to our Form 10-K for the year ended December 31, 1986).
10.10*	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to our Form 10-K for the fiscal year ended December 31, 1998).
10.11*	Form of 2004 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 10.12 to our Form 10-K filed March 11, 2005).
10.12*	Form of 2004 Performance-Based Deferred Stock Agreement among Williams and executive officers filed as Exhibit 10.13 to our Form 10-K filed March 11, 2005).
10.13*	Form of Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 2, 2005).
10.14*	Form of 2005 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 2, 2005).
10.15*	Form of 2005 Performance-Based Deferred Stock Agreement among Williams and executive officers.(filed as Exhibit 99.3 to our Form 8-K filed March 2, 2005).
10.16*	Form of 2006 Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Form 8-K filed March 7, 2006).
10.17*	Form of 2006 Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Form 8-K filed March 7, 2006).
10.18*	Form of 2006 Performance-Based Deferred Stock Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Form 8-K filed March 7, 2006).
10.19*	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to our Form S-8 filed August 1, 2001).
10.20*	The Williams Companies, Inc. 2002 Incentive Plan as amended and restated effective as of January 23, 2004 (filed as Exhibit 10.1 to our Form 10-Q filed on August 5, 2004).
10.21*	Form of Change in Control Severance Agreement between the Company and certain executive officers (filed as Exhibit 10.12 to our Form 10-Q filed November 14, 2002).
10.22*	Settlement Agreement, by and among the Governor of the State of California and the several other parties named therein and The Williams Companies, Inc. and Williams Energy Marketing &

	Trading Company dated November 11, 2002 (filed as Exhibit 10.79 to our Form 10-K for the fiscal year ended December 31, 2002).
10.23*	The Williams Companies, Inc. Severance Pay Plan as Amended and Restated Effective October 28, 2003.
10.24*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated October 28, 2003.
10.25*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated June 1, 2004.
10.26*	Amendment to The Williams Companies, Inc. Severance Pay Plan dated January 1, 2005.

Exhibit No.	Description
10.27*	U.S. $500,000,000 Term Loan Agreement among Williams Production Holdings LLC, Williams Production RMT Company, as Borrower, the Several Lenders from time to time parties thereto, Lehman Brothers Inc. and Banc of America Securities LLC as Joint Lead Arrangers, Citigroup USA, Inc. and JPMorgan Chase Bank, as Co-Syndication Agents, Bank of America, N.A., as Documentation Agent, and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.1 to our Form 10-Q filed August 12, 2003).
10.28*	The First Amendment to the Term Loan Agreement dated February 25, 2004, between Williams Production Holdings, LLC, Williams Production RMT Company, as Borrower, the several financial institutions as lenders and Lehman Commercial Paper Inc., as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.3 to our Form 10-Q filed May 6, 2004).
10.29*	Guarantee and Collateral Agreement made by Williams Production Holdings LLC, Williams Production RMT Company and certain of its Subsidiaries in favor of Lehman Commercial Paper Inc. as Administrative Agent dated as of May 30, 2003 (filed as Exhibit 10.2 to our Form 10-Q filed August 12, 2003).
10.30*	U.S. $1,275,000,000 Amended and Restated Credit Agreement Dated as of May 20, 2005 among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, Williams Partners L.P., as Borrowers, Citicorp USA, Inc., As Administrative Agent and Collateral Agent, Citibank, N.A. Bank of America, N.A. as Issuing Banks and The Banks Named Herein as Banks (filed as Exhibit 1.1 to our Form 8-K filed May 26, 2005).
10.31*	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 as Exhibit 10.1 to our form 8-K filed May 1, 2006).
10.32*	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 as Exhibit 10.3 to our Form 8-K filed on January 26, 2005).
10.33*	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 as Exhibit 10.4 to our Form 8-K filed on January 26, 2005).
10.34*	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 as Exhibit 10.3 to our Form 8-K filed on September 26, 2005).
10.35*	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 as Exhibit 10.3 to our Form 8-K filed on September 26, 2005).
10.36*	Assumption Agreement dated June 17, 2003 by and between The Williams Companies, Inc. and WEG Acquisitions, L.P. (filed as Exhibit 10.10 to our Form 10-Q filed August 12, 2003).
10.37*	Agreement for the Release of Certain Indemnification Obligations dated as of May 26, 2004 by and among Magellan Midstream Holdings, L.P., Magellan G.P. LLC and Magellan Midstream Partners, L.P., on the one hand, and The Williams Companies, Inc., Williams Energy Services, LLC, Williams Natural Gas Liquids, Inc. and Williams GP LLC, on the other hand (filed as

	Exhibit 10.6 to our Form 10-Q filed August 5, 2004).
10.38*	Master Professional Services Agreement dated as of June 1, 2004, by and between The Williams Companies, Inc. and International Business Machines Corporation (filed as Exhibit 10.2 to our Form 10-Q filed August 5, 2004).
10.39*	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 as Exhibit 10.3 to our Form 10-Q filed August 5, 2004).

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Exhibit No.	Description
10.40*	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 (incorporated by reference to Exhibit 2.1 to Williams Partners L.P. s current report on Form 8-K (File No. 1-32599) filed on November 21, 2006) filed as Exhibit 2.1 to our Form 8-K filed November 22, 2006).
10.41	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.
12	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.
14*	Code of Ethics (filed as Exhibit 14 to Form 10-K for the fiscal year ended December 31, 2003).
20*	Definitive Proxy Statement of Williams for 2007 (to be filed with the Securities and Exchange Commission on or before April , 2007).
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 together with certified resolution.
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.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.