UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): October 12, 2007

The Williams Companies, Inc.

(Exact name of registrant as specified in its charter)

Delaware	1-4174	73-0569878
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

One Williams Center, Tulsa, Oklahoma	74172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 918/573-2000

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240-14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events

On May 21, 2007, we announced a definitive agreement to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. We have revised certain historical financial information previously included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, and our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007, to reflect the results of operations and financial position of our power business as discontinued operations in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The following items of the Form 10-K have been revised for the discontinued operations described above and are filed as exhibits to this Current Report on Form 8-K:

- Item 6. Selected Financial Data
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
- Item 7A. Quantitative and Qualitative Disclosures About Market Risk
- Item 8. Financial Statements and Supplementary Data
- Exhibit 12. Computation of Ratio of Earnings to Fixed Charges for the years ended December 31, 2006, 2005, 2004, 2003, and 2002
- Exhibit 23.1. Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP

The following items of the Form 10-Q have been revised for the discontinued operations described above and are filed as exhibits to this Current Report on Form 8-K:

- Item 1. Financial Statements
- Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
- Item 3. Quantitative and Qualitative Disclosures About Market Risk
- Exhibit 12. Computation of Ratio of Earnings to Fixed Charges for the three months ended March 31, 2007

The revised items of the Form 10-K and Form 10-Q described above have been updated for only the power business discontinued operations. We have not otherwise updated for activities or events occurring after the dates these items were originally presented in the Form 10-K and Form 10-Q. This Current Report on Form 8-K should be read in conjunction with our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007, and other Current Reports on Form 8-K.

Item 9.01. Financial Statements and Exhibits

(a) None

(b) None

(c) None

(d) Exhibits

Exhibit No.	Description
12	Revised Computations of Ratio of Earnings to Fixed Charges for the years ended December 31, 2006, 2005, 2004, 2003, and 2002 and for the three months ended March 31, 2007.
23.1	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP.
99.1	Revised Selected Financial Data, Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk, and Financial Statements and Supplementary Data (Part II, Items 6, 7, 7A and 8 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006).
99.2	Schedule II — Valuation and Qualifying Accounts for each of the three years ended December 31, 2006
99.3	Revised Financial Statements, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk (Part I, Items 1, 2, and 3 of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007).

SIGNATURE

Pursuant to the requirements 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)

/s/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and Principal Accounting Officer)

October 12, 2007

INDEX TO EXHIBITS

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99.3	Revised Financial Statements, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk (Part I, Items 1, 2, and 3 of our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2007).

Exhibit 12

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

	Years Ended December 31,				
	2006	2005	2004	2003	2002
	(Dollars in millions)				
Earnings:					
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 557.9	$ 774.0	$ 298.5	$ (374.9)	$ (629.5)
Minority interest in income and preferred returns of consolidated subsidiaries	40.0	25.7	21.4	19.4	41.8
Less: Equity earnings	(98.9)	(65.6)	(49.9)	(20.3)	(82.7)
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles, minority interest in income and preferred returns of consolidated subsidiaries and equity earnings	499.0	734.1	270.0	(375.8)	(670.4)
Add:					
Fixed charges:					
Interest accrued, including proportionate share from 50% owned investees	694.2	680.1	821.8	1,274.0	1,172.2
Rental expense representative of interest factor	15.5	19.2	18.3	25.3	22.0
Preferred distributions	—	—	—	47.8	58.1
Total fixed charges	709.7	699.3	840.1	1,347.1	1,252.3
Distributed income of equity-method investees	113.0	107.7	60.5	21.5	81.3
Less:					
Capitalized interest	(17.2)	(7.2)	(6.7)	(45.5)	(27.3)
Preferred distributions	—	—	—	(47.8)	(58.1)
Total earnings as adjusted	$ 1,304.5	$ 1,533.9	$ 1,163.9	$ 899.5	$ 577.8
Fixed charges	$ 709.7	$ 699.3	$ 840.1	$ 1,347.1	$ 1,252.3
Ratio of earnings to fixed charges	1.84	2.19	1.39	(a)	(a)

(a) Earnings were inadequate to cover fixed charges by $447.6 million for the year ended December 31, 2003, and $674.5 million for the year ended December 31, 2002.

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges
(Dollars in millions)

	Three months ended March 31, 2007
Earnings:	
Income from continuing operations before income taxes	$ 274.3
Minority interest in income of consolidated subsidiaries	14.0
Less: Equity earnings	(21.4)
Income from continuing operations before income taxes, minority interest in income of consolidated subsidiaries and equity earnings	266.9
Add:	
Fixed charges:	
Interest accrued, including proportionate share from 50% owned investees	178.0
Rental expense representative of interest factor	4.4
Total fixed charges	182.4
Distributed income of equity-method investees	19.3
Less:	
Capitalized interest	(4.9)
Total earnings as adjusted	$ 463.7
Fixed charges	$ 182.4
Ratio of earnings to fixed charges	2.54

Exhibit 23.1

Consent Of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following registration statements on Form S-3 and Form S-4, and related prospectuses of The Williams Companies, Inc. and in the following registration statements on Form S-8 of our report dated February 22, 2007, except for the matters related to the sale of power business described in Note 2, as to which the date is October 8, 2007, with respect to the consolidated financial statements and schedule of The Williams Companies, Inc. included in this Current Report (Form 8-K).

Form S-3:

Registration Statement Nos. 333-20927, 333-20929, 333-29185, 333-35097, 333-70394, 333-85540, 333-106504, and 333-134293

Form S-4:

Registration Statement Nos. 333-57416, 333-63202, 333-85568, and 333-129779

Form S-8:

Registration No. 33-58671 —	The Williams Companies, Inc. Stock Plan for Nonofficer Employees
Registration No. 33-58971 —	Transco Energy Company Thrift Plan
Registration No. 333-03957 —	The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors
Registration No. 333-11151 —	The Williams Companies, Inc. 1996 Stock Plan
Registration No. 333-40721 —	The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees
Registration No. 333-51994 —	The Williams Companies, Inc. 1996 Stock Plan for Nonofficer Employees
Registration No. 333-66474 —	The Williams Companies, Inc. 2001 Stock Plan
Registration No. 333-76929 —	The Williams International Stock Plan
Registration No. 333-85542 —	The Williams Investment Plus Plan
Registration No. 333-85546 —	The Williams Companies, Inc. 2002 Incentive Plan
Registration No. 333-142985 —	The Williams Companies, Inc. Employee Stock Purchase Plan

/s/ Ernst & Young LLP

Tulsa, Oklahoma
October 8, 2007

Exhibit 99.1

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 recast 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)	$ 9,376.4	$ 9,781.4	$ 8,407.5	$ 8,615.0	$ 3,295.5
Income (loss) from continuing operations(2)	347.0	472.1	148.6	(248.0)	(433.1)
Income (loss) from discontinued operations(3)	(38.5)	(156.8)	15.1	517.1	(321.6)
Cumulative effect of change in accounting principles(4)	—	(1.7)	—	(761.3)	—
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	.57	.79	.28	(.54)	(1.01)
Income (loss) from discontinued operations	(.06)	(.26)	.03	1.00	(.62)
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* 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.

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

Sale of Power Business

On May 21, 2007, we announced our intent to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. This pending sale reduces the risk and complexity of our overall business model and allows our ongoing efforts to focus our investment capital and growth efforts on our core natural gas businesses. The sale is expected to close in 2007.

The pending sale of our power business to Bear Energy, LP, includes tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. Our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton), is currently being marketed for sale. These operations are part of our previously reported Power segment and are now reflected in our results of operations as discontinued operations. (See Notes 1 and 2 of Notes to Consolidated Financial Statements.)

Other continuing components of our former Power segment are now being reported as follows:

- Marketing and risk management operations that support our natural gas businesses are reflected in the new Gas Marketing Services segment.
- Our equity investment in Aux Sable Liquid Products, LP (Aux Sable) is now reported within the Midstream segment.
- Our natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility), is now reported within the Other segment.

General

We are primarily a natural gas company, engaged in finding, producing, gathering, processing, and transporting natural gas. Our operations are located principally in the United States and are organized into the following reporting segments: Exploration & Production, Gas Pipeline, Midstream Gas & Liquids (Midstream), and Gas Marketing Services. (See Note 1 of Notes to Consolidated Financial Statements 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 Item 8 of this document [Exhibit 99.1].

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 of $1,486.3 million 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.

Objectives	Highlights
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.

Our 2006 *income from continuing operations* decreased to $347.0 million, as compared to $472.1 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 resolution of certain legacy litigation issues partially offset by the benefit of strong natural gas liquid margins. 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.

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 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.

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	$9,376.4	$ -405.0	-4%	$9,781.4	$+1,373.9	+16%	$8,407.5
Costs and expenses:							
Costs and operating expenses	7,566.4	+318.3	+4%	7,884.7	-1,173.9	-17%	6,710.8
Selling, general and administrative expenses	389.3	-112.0	-40%	277.3	+12.7	+4%	290.0
Other (income) expense — net	33.3	+23.1	+41%	56.4	-109.8	NM	(53.4)
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	8,288.4			8,373.3			7,067.2
Operating income	1,088.0			1,408.1			1,340.3
Interest accrued — net	(652.6)	+7.3	+1%	(659.9)	+151.1	+19%	(811.0)
Investing income	167.6	+142.8	NM	24.8	-26.1	-51%	50.9
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	26.3	-0.8	-3%	27.1	+5.3	+24%	21.8
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	557.9			774.0			298.5
Provision for income taxes	210.9	+91.0	+30%	301.9	-152.0	-101%	149.9
Income from continuing operations	347.0			472.1			148.6
Income (loss) from discontinued operations	(38.5)	+118.3	+75%	(156.8)	-171.9	NM	15.1
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 natural gas realized revenues at Gas Marketing Services associated with lower natural gas sales prices. Additionally, the effect of a change in forward prices on legacy natural gas derivative contracts not designated as cash flow hedges had an unfavorable impact on revenues. Partially offsetting these decreases are increased crude, olefin and natural gas liquid (NGL) marketing revenues, higher NGL production revenue at Midstream and increased production revenue at Exploration & Production.

The decrease in *costs and operating expenses* is largely due to reduced natural gas purchase prices at Gas Marketing Services. 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 $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 Gas Marketing Services, 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 $30 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 primarily due to decreased pre-tax income. 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, 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:

- A $14.2 million net-of-tax loss related to our discontinued power business (see Note 2 of Notes to Consolidated Financial Statements);
- 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.

Income (loss) from discontinued operations in 2005 includes a $154.8 million net-of-tax loss related to our discontinued power business. (See Note 2 of Notes to Consolidated Financial Statements.)

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 higher natural gas prices and production volumes sold and gas management income at Exploration & Production, higher natural gas prices realized at Gas Marketing Services, and increased NGL prices and crude marketing revenue at Midstream.

The increase in *costs and operating expenses* is due primarily to increased natural gas purchase prices at Gas Marketing Services. Also contributing to the increase were higher crude marketing costs and NGL production costs at Midstream in addition to increased depreciation, depletion and amortization and gas management expense at Exploration & Production.

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 Gas Marketing Services 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 million 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 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 and a charge associated with charitable contribution carryovers. 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 and a $55.4 million net-of-tax loss related to our discontinued power business.

Results of Operations — Segments

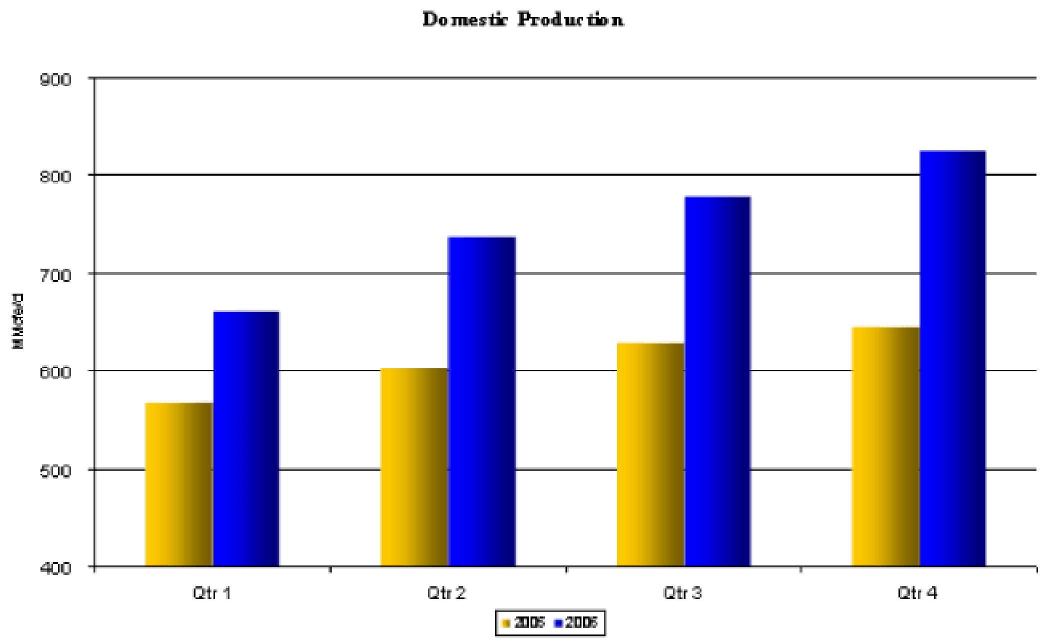
We are currently organized into the following segments: Exploration & Production, Gas Pipeline, Midstream, Gas Marketing Services, and Other. Other primarily consists of corporate operations. Our management currently evaluates performance based on segment profit (loss) from operations. (See Note 17 of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



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 Gas Marketing Services segment, which, in turn, executes offsetting derivative contracts with unrelated third parties. Generally, Gas Marketing Services 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.

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

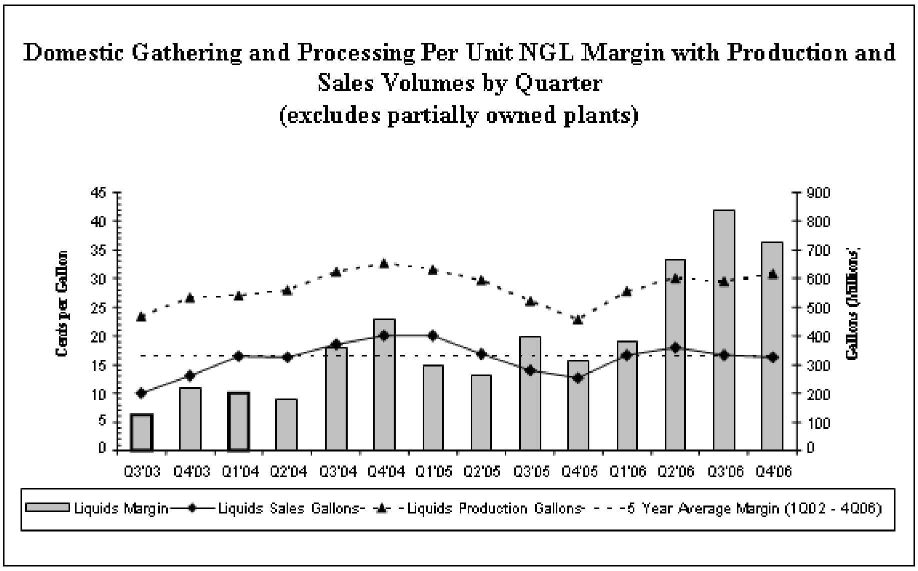
Overview of 2006

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.



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 totaling $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	16.4	42.4	137.9
Indirect general and administrative expense	(70.3)	(65.5)	(55.7)
Total	$ 671.3	$ 451.3	$ 553.6

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 $220 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, a settlement of an international contract dispute, and the absence of a $23 million impairment of our equity investment in Aux Sable Liquid Products L.P. (Aux Sable) recorded in 2005. These increases were 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 $26 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 the absence of a $23 million impairment of our equity investment in Aux Sable in 2005, $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 $102.3 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 and a $23 million impairment of our equity investment in Aux Sable in 2005. 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.

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 $95.5 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 in 2004, a $23 million impairment of our equity investment in Aux Sable in 2005, and a $9.5 million gain on the sale of the Choctaw ethylene distribution assets in 2004. Partially offsetting these decreases were $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.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, which were part of our former Power segment, including certain legacy natural gas contracts and positions.

Overview of 2006

Gas Marketing's operating results for 2006 reflect unrealized mark-to-market losses primarily caused by a decrease in forward natural gas prices against a net long derivative legacy position. Most of these derivative positions are economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

Outlook for 2007

For 2007, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment are included in the Gas Marketing segment. We intend to manage or liquidate a substantial portion of these legacy contracts in order to reduce risk and volatility.

Until such legacy positions are liquidated, Gas Marketing's earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but do not qualify for hedge accounting or are not designated as hedges for accounting purposes.

Year-Over-Year Results

	Years Ended December 31,		
	2006	2005	2004
		(Millions)	
Realized revenues	$ 5,184.3	$ 6,146.7	$ 4,991.3
Net forward unrealized mark-to-market gains (losses)	(135.7)	188.3	217.0
Segment revenues	5,048.6	6,335.0	5,208.3
Costs and operating expenses	5,257.5	6,237.6	5,043.2
Gross margin	(208.9)	97.4	165.1
Selling, general and administrative (income) expense	(12.7)	(.5)	7.8
Other (income) expense — net	(1.4)	88.8	3.9
Segment profit (loss)	$ (194.8)	$ 9.1	$ 153.4

2006 vs. 2005

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $962.4 million primarily due to a 17 percent decrease in average natural gas sales prices.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain legacy derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The effect of a change in forward prices on legacy natural gas derivative contracts primarily caused the $324 million unfavorable change in *net forward unrealized mark-to-market gains (losses)*. A decrease in forward natural gas prices during 2006 caused losses on legacy net forward gas fixed-price purchase contracts, while an increase in forward natural gas prices during 2005 caused gains on legacy net forward gas fixed-price purchase contracts.

The $980.1 million decrease in Gas Marketing's *costs and operating expenses* is primarily due to an 18 percent decrease in average natural gas purchase prices.

The favorable change in *selling, general and administrative (income) expense* is due primarily to increased gains from the sale of certain receivables to a third party. Gas Marketing recognized a $24.8 million gain in 2006 compared to a $9.7 million gain in 2005.

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) and a $4.6 million accrual for a regulatory settlement.

The $203.9 million change from a *segment profit* to a *segment loss* is primarily due to the effect of a change in forward prices on legacy natural gas derivative contracts, partially offset by favorable changes in *other (income) expense—net* described above.

2005 vs. 2004

The $1.2 billion increase in *realized revenues* is primarily due to a 33 percent increase in average natural gas sales prices. Hurricane Katrina, among other factors, contributed to the increase in prices.

A change in notional volumes on legacy natural gas derivative contracts, partially offset by the effect of a change in forward prices, primarily caused the $28.7 million decrease in *net forward unrealized mark-to-market gains (losses)*. The effect of a greater increase in forward natural gas prices on a lower notional volume of net forward gas fixed-price purchase contracts in 2005 compared to 2004 resulted in decreased unrealized mark-to-market gains. Also in 2005, Gas Marketing 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.

The $1.2 billion increase in Gas Marketing's *costs and operating expenses* is primarily due to a 44 percent increase in average natural gas purchase prices. Hurricane Katrina, among other factors, contributed to the increase in prices.

The favorable change in s*elling, general and administrative (income) expense* is 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 favorable change in *SG&A (income) expense. SG&A (income) expense* in 2004 includes a $6.3 million reduction of allowance for bad debts resulting from a 2004 settlement with certain California utilities.

Other (income) expense — net in 2005 includes an $82.2 million accrual for estimated litigation contingencies as previously discussed. *Other (income) expense — net* in 2004 includes $6.1 million in fees paid related to the sale of certain receivables to a third party.

The $144.3 million decrease in *segment profit* is primarily due to accruals in 2005 for litigation contingencies. In addition, the unfavorable changes in *gross margin* contributed to the decrease as well.

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.

Our natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility), is now reported within the Other segment. (See Note 2 of Notes to Consolidated Financial Statements.)

Year-Over-Year Operating Results

	Years Ended December 31,		
	2006	2005	2004
		(Millions)	
Segment revenues	$61.0	$ 85.5	$ 51.1
Segment loss	$ (9.1)	$ (113.9)	$ (54.1)

2006 vs. 2005

Other *segment loss* 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 they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 2 of Notes to Consolidated Financial Statements.)

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 Exploration & Production's forecasted sales of natural gas production and certain forecasted purchases of gas and purchases and sales of power related to our former Power segment's long-term structured contracts and owned generation under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). 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. The chart below reflects the fair value of derivatives held for nontrading purposes as of December 31, 2006, for Gas Marketing Services, Exploration & Production, Midstream, Other, and nontrading derivatives reported in assets and liabilities of discontinued operations.

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, a portion of which is included in assets of discontinued operations (see Note 2 of Notes to Consolidated Financial Statements), 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 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. 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. Also, our former power business has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010. These sales contracts and related fixed demand obligations are included in the anticipated sale of substantially all of our power business.

- 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.

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 ratios 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 former power business 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 2, 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, including obligations related to discontinued operations.

	2007	2008-2009	2010-2011 (Millions)	Thereafter	Total
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

Contractual obligations related to discontinued operations included in the table above are as follows:

	2007	2008-2009	2010-2011 (Millions)	Thereafter	Total
Operating leases (1)	$ 158	$ 321	$ 326	$ 1,080	$ 1,885
Purchase obligations:					
Fuel conversion and other service contracts (2) (5)	249	505	495	2,377	3,626
Other	1	3	3	10	17
Other long-term liabilities, including current portion:					
Physical and financial derivatives (3) (5)	181	63	18	10	272
Total	$ 589	$ 892	$ 842	$ 3,477	$ 5,800

(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 tolling agreement at our former Power segment that is accounted for as an operating lease. Sublease income related to discontinued operations consists of $328 million in 2007, $559 million in 2008-2009, and $258 million in 2010-2011.

(2) Our former Power segment 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 ($2.3 billion related to discontinued operations) 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.

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.

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 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. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations. 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
Gas Marketing Services	• Natural gas purchases and sales

Our assets and liabilities of discontinued operations also include derivative contracts that hedge or could potentially hedge the commodity price risk exposure from natural gas purchases and 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. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations.

Certain of the other 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.

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 sheets 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 9.01 as Exhibit 99.2. 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, except for the matters related to
the sale of power business described in Note 2, as to
which the date is October 8, 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
Gas Marketing Services	5,048.6	6,335.0	5,208.3
Other	61.0	85.5	51.1
Intercompany eliminations	(2,693.2)	(2,553.7)	(1,874.4)
Total revenues	9,376.4	9,781.4	8,407.5
Segment costs and expenses:			
Costs and operating expenses	7,566.4	7,884.7	6,710.8
Selling, general and administrative expenses	389.3	277.3	290.0
Other (income) expense — net	33.3	56.4	(53.4)
Total segment costs and expenses	7,989.0	8,218.4	6,947.4
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
Gas Marketing Services	(194.8)	9.1	153.4
Other	(9.1)	(3.3)	(27.0)
General corporate expenses	(132.1)	(145.5)	(119.8)
Securities litigation settlement and related costs	(167.3)	(9.4)	—
Total operating income	1,088.0	1,408.1	1,340.3
Interest accrued	(669.8)	(667.1)	(817.7)
Interest capitalized	17.2	7.2	6.7
Investing income	167.6	24.8	50.9
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	26.3	27.1	21.8
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	557.9	774.0	298.5
Provision for income taxes	210.9	301.9	149.9
Income from continuing operations	347.0	472.1	148.6
Income (loss) from discontinued operations	(38.5)	(156.8)	15.1
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	$ .58	$ .82	$ .28
Income (loss) from discontinued operations	(.06)	(.27)	.03
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	$ .57	$ .79	$ .28
Income (loss) from discontinued operations	(.06)	(.26)	.03
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.

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 $14.8 million in 2006 and $86.5 million in 2005)	980.8	1,286.0
Inventories	237.6	269.0
Derivative assets	1,285.5	3,354.6
Margin deposits	59.3	349.2
Assets of discontinued operations	837.3	2,296.0
Deferred income taxes	337.2	241.0
Other current assets and deferred charges	224.1	211.4
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	14,157.6	12,383.4
Derivative assets	1,844.0	3,487.8
Goodwill	1,011.4	1,014.5
Assets of discontinued operations	564.5	1,196.1
Other assets and deferred charges	602.4	739.2
Total assets	$ 25,402.4	$ 29,442.6
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 906.3	$ 1,038.8
Accrued liabilities	1,223.6	1,083.7
Customer margin deposits payable	128.7	320.7
Derivative liabilities	1,303.6	3,925.4
Liabilities of discontinued operations	739.3	1,959.0
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	1,920.2	3,851.1
Liabilities of discontinued operations	146.5	495.9
Other liabilities and deferred income	986.2	904.4
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.

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.

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:			
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	154.2	(46.6)	131.7
Provision for loss on investments, property and other assets	25.5	118.7	86.7
Net gain on dispositions of assets	(22.5)	(58.8)	(215.4)
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	385.7	(242.0)	297.0
Inventories	31.3	(9.7)	(59.3)
Margin deposits and customer margin deposits payable	97.9	85.5	414.1
Other current assets and deferred charges	(34.2)	5.9	134.0
Accounts payable	(183.9)	233.3	(220.9)
Accrued liabilities	(109.6)	27.1	(19.6)
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	(117.6)
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)	(3,264.4)
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	1,103.2	36.5	(3,505.5)
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(2,509.2)	(1,299.0)	(788.3)
Net proceeds from dispositions	22.9	47.3	12.1
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	(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

* Revised as discussed in Note 1.

See accompanying notes.

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

Description of Business

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

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

Gas Marketing primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, which were part of our former Power segment, including certain legacy natural gas contracts and positions.

Basis of Presentation

On May 21, 2007, we announced a definitive agreement to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. In addition, we expect to sell certain remaining power assets later this year. We have retained the exposure related to certain contingent liabilities associated with our power business.

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”, the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our power business as discontinued operations. (See Note 2.) These operations, which were part of our previously reported Power segment, include our 7,500-megawatt portfolio of power-related contracts being sold to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton).

We have recast all segment information in the Notes to Consolidated Financial Statements for the prior periods presented to reflect the discontinued operations noted above. This also reflects the creation of a new Gas Marketing Services segment, which includes certain continued marketing and risk management operations that support our natural gas businesses. These operations were part of our previously reported Power segment but will now be managed and reported as a separate segment.

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.

Cash flows are presented without separate disclosure of discontinued operations. Amounts reported for the prior period have been revised with no material impact. This revision did not change the total reported net cash provided or used by operating, financing, or investing activities.

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.

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 our 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 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.

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 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, our former Power segment'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, our former Power segment's derivative contracts became eligible for hedge accounting. Our former Power segment 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.*

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 our former Power segment'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 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.

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, of which $2.9 million is included in *income (loss) from discontinued operations*. 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 $17.6 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).

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)* .

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 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 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 or approved for sale by our Board of Directors and are classified as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses) and financial position have been reflected in the consolidated financial statements and notes as discontinued operations.

Sale of power business

On May 21, 2007, we announced a definitive agreement to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. Under the agreement, this amount will be reduced by expected net portfolio cash flows from an April 1, 2007, valuation date through the transaction closing date. Mark-to-market gains and losses between this valuation date and the close of the transaction will not impact the economic value of the sale, although they may change the recorded gain or loss on the sale as derivative assets and liabilities included in the transaction continue to be valued at fair value. We expect the sale to close in 2007.

In addition, we expect to sell certain remaining power assets. We will retain the exposure related to certain contingent liabilities associated with our power business. (See Note 15.) The following table outlines the impact to our previously reported Power segment.

Previous Power Segment Component	New Presentation
Portfolio of power-related contracts, including tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software	Being sold to Bear Energy, LP and reported as discontinued operations
Natural gas-fired electric generating plant near Hazleton, Pennsylvania	Being marketed for sale and reported as discontinued operations
Marketing and risk management operations associated with managing our natural gas businesses	Retained and reported within the new Gas Marketing Services segment
Equity investment in Aux Sable Liquid Products, LP (Aux Sable)	Retained and reported within the Midstream segment
Natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility)	Reported within the Other segment, as we continue to evaluate whether to retain or sell

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	2004
		(Millions)	
Revenues	$ 2,436.5	$ 2,802.3	$ 4,053.8
Loss from discontinued operations before income taxes	$ (58.1)	$ (246.6)	$ (195.2)
Gain on sales	—	.5	200.5
Benefit for income taxes	19.6	89.3	9.8
Income (loss) from discontinued operations	$ (38.5)	$ (156.8)	$ 15.1

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of December 31, 2006 and 2005.

	December 31, 2006	December 31, 2005
	(Millions)	
Derivative assets	$ 592.7	$ 1,945.1
Accounts receivable — net	232.1	327.8
Other current assets	11.9	22.6
Total current assets	836.7	2,295.5
Property, plant and equipment — net	23.5	26.2
Derivative assets	540.9	1,169.1
Other noncurrent assets	.7	1.3
Total noncurrent assets	565.1	1,196.6
Total assets	$ 1,401.8	$ 3,492.1
Reflected on balance sheet as:		
Current assets	$ 837.3	$ 2,296.0
Noncurrent assets	564.5	1,196.1
Total assets	$ 1,401.8	$ 3,492.1
Derivative liabilities	$ 479.3	$ 1,597.8
Other current liabilities	259.7	360.8
Total current liabilities	739.0	1,958.6
Derivative liabilities	123.6	480.0
Other noncurrent liabilities	23.2	16.3
Total noncurrent liabilities	146.8	496.3
Total liabilities	$ 885.8	$ 2,454.9
Reflected on balance sheet as:		
Current liabilities	$ 739.3	$ 1,959.0
Noncurrent liabilities	146.5	495.9
Total liabilities	$ 885.8	$ 2,454.9

2006 Activities

During 2006, we recorded charges of $19.2 million for an adverse arbitration award related to our former chemical fertilizer business, $6 million for a loss contingency in connection with a former exploration business, and $14.7 million associated with an oil purchase contract related to our former Alaska refinery. In addition, we recorded income of $12.7 million related to the reduction of contingent obligations associated with our former distributive power business.

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	89.1	70.5	65.0
Total	$ 167.6	$ 24.8	$ 50.9

* 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, which is included in our Midstream 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;
- 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 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.

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)
Gas Marketing Services			
Accrual for litigation contingencies	—	82.2	—
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.)

Note 5. Provision for Income Taxes

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

	2006	2005	2004
		(Millions)	
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	146.1	23.6	91.2
State	4.1	27.1	41.2
Foreign	23.6	(8.0)	9.2
	173.8	42.7	141.6
Total provision	$ 210.9	$ 301.9	$ 149.9

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	2004
		(Millions)	
Provision at statutory rate	$ 195.3	$ 271.0	$ 104.5
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	7.0	29.0	29.9
Foreign operations — net	22.8	2.2	1.3
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)	(.3)
Provision for income taxes	$ 210.9	$ 301.9	$ 149.9

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 $144 million, $72 million, and $64 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.

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.

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)	$ 347.0	$ 472.1	$ 148.6
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	$ .58	$ .82	$ .28
Diluted	$ .57	$ .79	$ .28

(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.

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. We do not expect that the sale of our power business will have a significant impact on our employee benefit plans. (See Note 2.)

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 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)	After SFAS No. 158 Adoption(1)
		(Millions)	
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.

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.

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		

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 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	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	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

	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

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.

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.

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	Federal Prescription Drug Subsidy
		(Millions)	
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	82.1	78.6
	$ 237.6	$ 269.0

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
Gas Marketing Services	68.7	67.8
Other	289.8	279.6
	19,949.5	17,528.8
Accumulated depreciation, depletion and amortization	(5,791.9)	(5,145.4)
	$14,157.6	$12,383.4

(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 $862.5 million in 2006, $735.9 million in 2005, and $662.3 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.

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	155.2	139.4
Taxes other than income taxes	151.8	141.3
Accrual for Gulf Liquids litigation contingency	94.7*	—
Income taxes	80.8	58.2
Accrual for Williams Power Company, Inc. (WPC) 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	379.4	385.5
	$ 1,223.6	$ 1,083.7

* Includes $22 million of interest

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.
- 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.

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	$ 67.4
2008	67.4
2009	44.7
2010	23.3
2011	15.9
Thereafter	41.4
Total	$ 260.1

The above amounts do not include obligations of approximately $1.9 billion related to a tolling agreement 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.) The tolling agreement allows for the exclusive right to capacity and fuel conversion services as well as ancillary services associated with electric generation facilities that are currently in 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. This tolling agreement is included in the pending sale of our power business to Bear Energy, LP. (See Note 2.)

Total rent expense was $68 million in 2006, $65 million in 2005 and $69 million in 2004. Rent expense reported as discontinued operations, 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. Rent expense from discontinued operations 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.

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

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	Weighted-Average Fair Value*
	(Millions)	
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
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$ 23.39	$ 19.35	$ 10.54
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.

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.

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(d)	365.1	365.1	(5.5)	(5.5)
Other energy derivatives(d)	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.

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

Energy Derivatives

Our energy derivative contracts include the following:

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

Forward contracts: Forward contracts are over-the-counter commitments to either purchase or sell a commodity at a future date for a specified price, which involve physical delivery of energy commodities, and may contain either fixed or variable pricing terms. Forward contracts are 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 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 former 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.

The electric generation facilities and tolling agreements of our former Power segment 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.

Gas Marketing Services' and our former Power segment'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* 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 will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Our former Power segment 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.

Other energy derivatives

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

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 Gas Marketing Services and discontinued operations 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, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to 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 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 including those related to discontinued operations (see Note 2), 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.

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, a portion of which is included in assets of discontinued operations (see Note 2), 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. 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

Our subsidiary, WPC, whose results of operations were included in our previously reported Power segment (see Note 2), is 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 WPC entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which WPC sold electricity, totaled approximately $89 million in revenue. While WPC is not a party to the cases involved in the appellate court decision, the buyer of electricity from WPC is a party to the cases and claims that WPC 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 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 WPC 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. Gas Marketing Services 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, Gas Marketing Services 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.

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 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- 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 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 WPC. 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 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, WPC received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and WPC, 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 WPC jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $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 WPC 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 WPC 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.

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.

Commitments

WPC 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, WPC'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. These contracts are included in the pending sale of our power business to Bear Energy, LP. (See Note 2.)

Commitments for construction and acquisition of property, plant and equipment are approximately $406 million at December 31, 2006.

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)
Income tax benefit (provision)	—	—	—	(3.1)	2.2	92.5	2.6	9.9	104.1
	—	—	—	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.

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

On May 21, 2007, we announced that we had entered into a definitive agreement to sell substantially all of our power business to Bear Energy, LP. This pending sale has impacted our segment presentation. See Notes 1 and 2 for further discussion.

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 and our Milagro natural gas-fired electric generating plant. (See Note 2.)

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 *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.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with our Gas Marketing Services segment which, in turn, entered into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with the unrelated third parties.

The Gas Marketing Services segment includes the continued marketing and risk management operations that support our natural gas businesses. The operations include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing Services manages various natural gas-related contracts such as transportation, storage, and related hedges.

External revenues of our Exploration & Production segment includes third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

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

	United States	Other	Total
		(Millions)	
Revenues from external customers:			
2006	$ 8,981.8	$394.6	$ 9,376.4
2005	9,465.7	315.7	9,781.4
2004	8,122.9	284.6	8,407.5
Long-lived assets:			
2006	$ 14,487.3	$681.7	$15,169.0
2005	12,666.9	739.8	13,406.7
2004	12,119.9	762.0	12,881.9

Our foreign operations are primarily located in Venezuela, Canada, and Argentina. *Long-lived assets* are comprised of property, plant and equipment, goodwill and other intangible assets.

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income and *other financial information* related to *long-lived assets.*

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
2006							
Segment revenues:							
External	$ (189.9)	$1,335.6	$ 4,071.1	$4,127.2	$ 32.4	$ —	$9,376.4
Internal	1,677.5	12.1	53.6	921.4	28.6	(2,693.2)	—
Total revenues	$ 1,487.6	$1,347.7	$ 4,124.7	$5,048.6	$ 61.0	$ (2,693.2)	$9,376.4
Segment profit (loss)	$ 551.5	$ 467.4	$ 671.3	$ (194.8)	$ (9.1)	$ —	$1,486.3
Less equity earnings	21.8	37.1	40.0	—	—	—	98.9
Segment operating income (loss)	$ 529.7	$ 430.3	$ 631.3	$ (194.8)	$ (9.1)	$ —	1,387.4
General corporate expenses							(132.1)
Securities litigation settlement and related costs							(167.3)
Consolidated operating income							$1,088.0
Other financial information:							
Additions to long-lived assets	$ 1,495.7	$ 913.2	$ 279.4	$ .9	$ 18.1	$ —	$2,707.3
Depreciation, depletion & amortization	$ 360.2	$ 281.7	$ 201.2	$ 6.7	$ 13.1	$ —	$ 862.9
2005							
Segment revenues:							
External	$ (201.6)	$1,395.0	$ 3,187.6	$5,365.9	$ 34.5	$ —	$9,781.4
Internal	1,470.7	17.8	45.1	969.1	51.0	(2,553.7)	—
Total revenues	$ 1,269.1	$1,412.8	$ 3,232.7	$6,335.0	$ 85.5	$ (2,553.7)	$9,781.4
Segment profit (loss)	$ 587.2	$ 585.8	$ 451.3	$ 9.1	$ (113.9)	$ —	$1,519.5
Less:							
Equity earnings (losses)	18.8	43.6	26.7	—	(23.5)	—	65.6
Loss from investments	—	—	(22.0)	—	(87.1)	—	(109.1)
Segment operating income (loss)	$ 568.4	$ 542.2	$ 446.6	$ 9.1	$ (3.3)	$ —	1,563.0
General corporate expenses							(145.5)
Securities litigation settlement and related costs							(9.4)
Consolidated operating income							$1,408.1
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	$ 9.7	$ 13.7	$ —	$ 736.9
2004							
Segment revenues:							
External	$ (84.0)	$1,345.0	$ 2,844.7	$4,274.5	$ 27.3	$ —	$8,407.5
Internal	861.6	17.3	37.9	933.8	23.8	(1,874.4)	—
Total revenues	$ 777.6	$1,362.3	$ 2,882.6	$5,208.3	$ 51.1	$ (1,874.4)	$8,407.5
Segment profit (loss)	$ 235.8	$ 585.8	$ 553.6	$ 153.4	$ (54.1)	$ —	$1,474.5
Less:							
Equity earnings (losses)	11.9	29.2	18.5	—	(9.7)	—	49.9
Loss from investments	—	(1.0)	(17.1)	—	(17.4)	—	(35.5)
Segment operating income (loss)	$ 223.9	$ 557.6	$ 552.2	$ 153.4	$ (27.0)	$ —	1,460.1
General corporate expenses							(119.8)
Consolidated operating income							$1,340.3
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	$ 13.1	$ 15.3	$ —	$ 663.5

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	5,465.8	4,646.6	4,197.2	323.2	333.4	318.9
Gas Marketing Services(2)	5,519.1	11,464.0	5,285.0	—	—	—
Other	3,954.7	3,631.3	3,265.8	—	.2	113.2
Eliminations(3)	(7,121.6)	(10,044.4)	(4,698.7)	—	—	—
	24,000.6	25,950.5	21,277.5	814.4	831.1	1,246.5
Discontinued operations	1,401.8	3,492.1	2,715.5	—	—	—
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 Gas Marketing Services segment.

(2) The 2006 decrease and 2005 increase in Gas Marketing Services' 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. Gas Marketing Services' 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.

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	$2,387.1	$2,219.7	$2,511.8	$2,257.8
Costs and operating expenses	1,962.2	1,777.1	2,039.6	1,787.5
Income (loss) from continuing operations	132.0	(59.0)	112.9	161.1
Net income (loss)	131.9	(76.0)	106.2	146.4
Basic earnings per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.27
Diluted earnings per common share:				
Income (loss) from continuing operations	.22	(.10)	.19	.26
2005				
Revenues	$2,255.8	$2,222.5	$2,335.2	$2,967.9
Costs and operating expenses	1,721.5	1,794.2	1,936.9	2,432.1
Income from continuing operations	193.4	82.0	102.1	94.6
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	.35	.14	.18	.17
Income before cumulative effect of change in accounting principle	.36	.07	.01	.12
Diluted earnings per common share:				
Income from continuing operations	.33	.14	.17	.15
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 (see Note 2);
- $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).

Net income (loss) for second quarter 2006 includes the following pre-tax items:

- $160.7 million accrual related to our securities litigation settlement (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 (see Note 12);
- $23.7 million gain on sale of certain receivables at Gas Marketing Services;
- $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 Gas Marketing Services (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 Midstream (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 Gas Marketing Services (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).

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.
- 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 (Millions)	2004
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.
- 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	2004
		(Bcfe)	
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.

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	At December 31, 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	2004
		(Millions)	
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

Exhibit 99.2

THE WILLIAMS COMPANIES, INC.

SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	ADDITIONS Charged to Cost and Expenses	ADDITIONS Other	Deductions	Ending Balance
			(Millions)		
Year ended December 31, 2006:					
Allowance for doubtful accounts — accounts and notes receivable(a)	$ 86.5	$ 3.7	$ (65.6)(e)	$ 9.8(c)	$ 14.8
Price-risk management credit reserves(a)	14.9	(8.2)(d)	—	—	6.7
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)	98.1	3.5	—	15.1(c)	86.5
Price-risk management credit reserves(a)	3.0	11.9(d)	—	—	14.9
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)	102.8	(.8)	—	3.9(c)	98.1
Price-risk management credit reserves(a)	1.2	1.8(d)	—	—	3.0
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) During 2006, $65.6 million in previously reserved Enron receivables were sold.

Exhibit 99.3

The Williams Companies, Inc.
Consolidated Statement of Income
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended March 31, 2007	2006
Revenues:		
Exploration & Production	$ 482.7	$ 356.0
Gas Pipeline	370.8	334.0
Midstream Gas & Liquids	995.4	979.4
Gas Marketing Services	1,288.3	1,424.0
Other	13.6	19.2
Intercompany eliminations	(782.5)	(725.5)
Total revenues	2,368.3	2,387.1
Segment costs and expenses:		
Costs and operating expenses	1,843.3	1,962.2
Selling, general and administrative expenses	102.5	57.8
Other income — net	(17.9)	(21.6)
Total segment costs and expenses	1,927.9	1,998.4
General corporate expenses	39.4	31.8
Operating income (loss):		
Exploration & Production	182.8	142.6
Gas Pipeline	140.4	127.2
Midstream Gas & Liquids	147.4	141.6
Gas Marketing Services	(29.8)	(23.4)
Other	(.4)	.7
General corporate expenses	(39.4)	(31.8)
Total operating income	401.0	356.9
Interest accrued	(172.0)	(161.3)
Interest capitalized	4.9	3.0
Investing income	52.4	47.7
Early debt retirement costs	—	(27.0)
Minority interest in income of consolidated subsidiaries	(14.0)	(7.1)
Other income — net	2.0	8.0
Income from continuing operations before income taxes	274.3	220.2
Provision for income taxes	104.6	88.2
Income from continuing operations	169.7	132.0
Loss from discontinued operations	(35.7)	(.1)
Net income	$ 134.0	$ 131.9
Basic earnings (loss) per common share:		
Income from continuing operations	$ .28	$ .22
Loss from discontinued operations	(.06)	—
Net income	$ .22	$ .22
Weighted-average shares (thousands)	598,031	591,407
Diluted earnings (loss) per common share:		
Income from continuing operations	$ .28	$ .22
Loss from discontinued operations	(.06)	—
Net income	$ .22	$ .22
Weighted-average shares (thousands)	611,470	607,073
Cash dividends declared per common share	$ .09	$ .075

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	March 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,811.2	$ 2,268.6
Restricted cash	57.1	91.6
Accounts and notes receivable (net of allowance of $13.7 in 2007 and $14.8 in 2006)	1,049.2	980.8
Inventories	262.2	237.6
Derivative assets	1,656.5	1,285.5
Margin deposits	99.6	59.3
Assets of discontinued operations	767.2	837.3
Deferred income taxes	363.8	337.2
Other current assets and deferred charges	353.9	224.1
Total current assets	6,420.7	6,322.0
Restricted cash	34.5	34.5
Investments	868.7	866.0
Property, plant and equipment — net	14,428.3	14,157.6
Derivative assets	1,978.8	1,844.0
Goodwill	1,011.4	1,011.4
Assets of discontinued operations	650.3	564.5
Other assets and deferred charges	543.3	602.4
Total assets	$25,936.0	$ 25,402.4
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 949.4	$ 906.3
Accrued liabilities	1,087.2	1,223.6
Customer margin deposits payable	203.5	128.7
Derivative liabilities	1,776.3	1,303.6
Liabilities of discontinued operations	628.4	739.3
Long-term debt due within one year	387.7	392.1
Total current liabilities	5,032.5	4,693.6
Long-term debt	7,507.5	7,622.0
Deferred income taxes	2,961.4	2,879.9
Derivative liabilities	2,079.1	1,920.2
Liabilities of discontinued operations	205.5	146.5
Other liabilities and deferred income	880.9	986.2
Contingent liabilities and commitments (Note 9)		
Minority interests in consolidated subsidiaries	1,077.4	1,080.8
Stockholders' equity:		
Common stock (960 million shares authorized at $1 par value; 604.2 million issued at March 31, 2007 and 602.8 million shares issued at December 31, 2006)	604.2	602.8
Capital in excess of par value	6,641.8	6,605.7
Accumulated deficit	(970.9)	(1,034.0)
Accumulated other comprehensive loss	(42.2)	(60.1)
	6,232.9	6,114.4
Less treasury stock, at cost (5.7 million shares of common stock in 2007 and 2006)	(41.2)	(41.2)
Total stockholders' equity	6,191.7	6,073.2
Total liabilities and stockholders' equity	$25,936.0	$ 25,402.4

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

(Dollars in millions)	Three months ended March 31, 2007	2006*
OPERATING ACTIVITIES:		
Net income	$ 134.0	$ 131.9
Adjustments to reconcile to net cash provided by operations:		
Depreciation, depletion and amortization	248.2	197.0
Provision for deferred income taxes	73.4	75.1
Provision for loss on investments, property and other assets	3.6	2.4
Net gain on disposition of assets	(.7)	(10.3)
Early debt retirement costs	—	27.0
Minority interest in income of consolidated subsidiaries	14.0	7.1
Amortization of stock-based awards	16.8	10.5
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(61.5)	440.5
Inventories	(24.8)	(5.2)
Margin deposits and customer margin deposits payable	34.5	(150.1)
Other current assets and deferred charges	3.2	(46.1)
Accounts payable	3.4	(313.1)
Accrued liabilities	(189.4)	(213.6)
Changes in current and noncurrent derivative assets and liabilities	67.8	21.7
Other, including changes in noncurrent assets and liabilities	(22.7)	(10.1)
Net cash provided by operating activities	299.8	164.7
FINANCING ACTIVITIES:		
Payments of long-term debt	(118.6)	(64.1)
Proceeds from issuance of common stock	14.5	10.2
Premiums paid on early debt retirement costs	—	(25.8)
Tax benefit of stock-based awards	7.6	—
Dividends paid	(54.1)	(44.6)
Dividends and distributions paid to minority interests	(20.3)	(6.6)
Changes in restricted cash	34.7	7.3
Changes in cash overdrafts	17.0	(31.0)
Other — net	3.1	(1.2)
Net cash used by financing activities	(116.1)	(155.8)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(509.1)	(468.3)
Net proceeds from dispositions	.2	12.5
Changes in accounts payable and accrued liabilities	(5.7)	14.5
Purchases of investments/advances to affiliates	(21.2)	(9.7)
Purchases of auction rate securities	(173.2)	(95.3)
Proceeds from sales of auction rate securities	44.6	19.4
Proceeds from dispositions of investments and other assets	17.8	31.4
Other — net	5.5	4.4
Net cash used by investing activities	(641.1)	(491.1)
Decrease in cash and cash equivalents	(457.4)	(482.2)
Cash and cash equivalents at beginning of period	2,268.6	1,597.2
Cash and cash equivalents at end of period	$ 1,811.2	$ 1,115.0

* Revised as discussed in Note 2.

See accompanying notes.

Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at March 31, 2007, and results of operations and cash flows for the three months ended March 31, 2007 and 2006.

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

Note 2. Basis of Presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our power business as discontinued operations. (See Note 3.) These operations, which were part of our previously reported Power segment, include:

- Our 7,500-megawatt portfolio of power-related contracts being sold to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. This includes tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software.
- Our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton).

We have recast all segment information in the Notes to Consolidated Financial Statements to reflect the discontinued operations noted above. This also reflects the creation of a new Gas Marketing Services segment, which includes certain continued marketing and risk management operations that support our natural gas businesses. These operations were part of our previously reported Power segment but will now be managed and reported as a separate segment.

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

Cash flows are presented without separate disclosure of discontinued operations. Amounts reported have been revised with no material impact. This revision did not change the total reported net cash provided or used by operating, financing, or investing activities.

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. Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment 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.”

Note 3. Discontinued Operations

On May 21, 2007, we announced a definitive agreement to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. Under the agreement, this amount will be reduced by expected net portfolio cash flows from an April 1, 2007, valuation date through the transaction closing date. Mark-to-market gains and losses between this valuation date and the close of the transaction will not impact the economic value of the sale, although they may change the recorded gain or loss on the sale as derivative assets and liabilities included in the transaction continue to be valued at fair value. We expect the sale to close in 2007.

In addition, we expect to sell certain remaining power assets. We have retained the exposure related to certain contingent liabilities associated with our power business. (See Note 9.) The following table outlines the impact to our previously reported Power segment.

Previous Power Segment Component	New Presentation
Portfolio of power-related contracts, including tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software	Being sold to Bear Energy, LP and reported as discontinued operations
Natural gas-fired electric generating plant near Hazleton, Pennsylvania	Being marketed for sale and reported as discontinued operations
Marketing and risk management operations associated with managing our natural gas businesses	Retained and reported within the new Gas Marketing Services segment
Equity investment in Aux Sable Liquid Products, LP (Aux Sable)	Retained and reported within the Midstream segment
Natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility)	Reported within the Other segment, as we continue to evaluate whether to retain or sell

Summarized results of discontinued operations

The following table presents the summarized results of discontinued operations for the three months ended March 31, 2007 and 2006.

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Revenues	$ 483.8	$ 640.4
Income (loss) from discontinued operations before income taxes	(57.3)	.5
Benefit (provision) for income taxes	21.6	(.6)
Loss from discontinued operations	$ (35.7)	$ (.1)

Notes (Continued)

Summarized assets and liabilities of discontinued operations

The following table presents the summarized assets and liabilities of discontinued operations as of March 31, 2007 and December 31, 2006.

	March 31, 2007	December 31, 2006
	(Millions)	
Derivative assets	$ 533.8	$ 592.7
Accounts receivable — net	222.6	232.1
Other current assets	10.8	11.9
Total current assets	767.2	836.7
Property, plant and equipment — net	22.7	23.5
Derivative assets	627.2	540.9
Other noncurrent assets	.4	.7
Total noncurrent assets	650.3	565.1
Total assets	$1,417.5	$ 1,401.8
Reflected on balance sheet as:		
Current assets	$ 767.2	$ 837.3
Noncurrent assets	650.3	564.5
Total assets	$1,417.5	$ 1,401.8
Derivative liabilities	$ 365.2	$ 479.3
Other current liabilities	263.2	259.7
Total current liabilities	628.4	739.0
Derivative liabilities	187.3	123.6
Other noncurrent liabilities	18.2	23.2
Total noncurrent liabilities	205.5	146.8
Total liabilities	$ 833.9	$ 885.8
Reflected on balance sheet as:		
Current liabilities	$ 628.4	$ 739.3
Noncurrent liabilities	205.5	146.5
Total liabilities	$ 833.9	$ 885.8

Note 4. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended March 31, 2007	2006
	(Millions)	
Current:		
Federal	$ 2.8	$ 3.1
State	(2.4)	2.6
Foreign	9.3	8.0
	9.7	13.7
Deferred:		
Federal	76.2	56.3
State	12.7	12.6
Foreign	6.0	5.6
	94.9	74.5
Total provision	$ 104.6	$ 88.2

The effective tax rate for the three months ended March 31, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and net foreign operations.

The effective tax rate for the three months ended March 31, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes.

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" (FIN 48). 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 as 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 was approximately a $16.8 million decrease in retained earnings.

As of January 1, 2007, we had approximately $93 million of unrecognized tax benefits. If recognized, approximately $83 million, net of federal tax expense, would be recorded as a reduction of income tax expense. There have been no significant changes to these amounts during the quarter ended March 31, 2007.

We recognize related interest and penalties as a component of income tax expense. Approximately $97 million of interest and $5 million of penalties have been accrued at January 1, 2007. Of the $97 million interest accrued, approximately $22 million relates to uncertain tax positions.

As of January 1, 2007, the Internal Revenue Service (IRS) examination of Williams' consolidated U.S. income tax return for 2002 was in process. During the first quarter of 2007, the IRS also commenced examination of the 2003 through 2005 consolidated U.S. income tax returns. IRS examinations for 1996 through 2001 have been completed but the years remain open while certain issues are under review with the Appeals Division of the IRS. The statute of limitations for most states expire one year after IRS audit settlement.

Generally, tax returns for our Venezuelan and Canadian entities are open to audit from 2002 through 2006. Certain Canadian entities are currently under examination.

Note 5. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share are computed as follows:

	Three months ended March 31, 2007	2006
	(Dollars in millions, except per share amounts; shares in thousands)	
Income from continuing operations available to common stockholders for basic and diluted earnings per share (1)	$ 169.7	$ 132.0
Basic weighted-average shares	598,031	591,407
Effect of dilutive securities:		
Unvested restricted stock units (2)	1,363	834
Stock options	4,751	4,355
Convertible debentures (3)	7,325	10,477
Diluted weighted-average shares	611,470	607,073
Earnings per common share from continuing operations:		
Basic	$ .28	$ .22
Diluted	$ .28	$ .22

(1) The three months ended March 31, 2007 and 2006 include approximately $.7 million and $1 million, respectively, of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

Notes (Continued)

(2) The unvested restricted stock units outstanding at March 31, 2007, will vest over the period from May 2007 to March 2010.

(3) During January 2006, we converted approximately $220.2 million of our 5.5 percent junior subordinated convertible debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest. At March 31, 2007, approximately $80 million of our convertible debentures remain outstanding.

The table below includes information related to stock options that were outstanding at March 31 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first quarter weighted-average market price of our common shares.

	March 31, 2007	March 31, 2006
Options excluded (millions)	4.4	4.6
Weighted-average exercise prices of options excluded	$34.19	$35.35
Exercise price ranges of options excluded	$27.15–$42.29	$22.68–$42.29
First quarter weighted-average market price	$27.04	$22.40

In the first quarter of 2006, an additional 3.2 million options with exercise prices less than the first quarter weighted-average market price were excluded from the computation of weighted-average stock options due to the shares being antidilutive.

Note 6. Employee Benefit Plans

Net periodic pension expense and *other postretirement benefit expense* for the three months ended March 31, 2007 and 2006 are as follows. We do not expect that the sale of our power business will have a significant impact on our employee benefit plans. (See Note 3.)

	Pension Benefits Three months ended March 31,		Other Postretirement Benefits Three months ended March 31,	
	2007	2006	2007	2006
	(Millions)			
Components of net periodic pension and other postretirement benefit expense:				
Service cost	$ 5.8	$ 5.7	$ .8	$ .9
Interest cost	13.1	11.8	4.4	5.2
Expected return on plan assets	(17.9)	(16.9)	(3.0)	(2.9)
Amortization of prior service credit	(.1)	(.1)	(.1)	(.1)
Amortization of net actuarial loss	4.1	3.8	—	.9
Regulatory asset amortization (deferral)	—	(.1)	1.3	1.6
Net periodic pension and other postretirement benefit expense	$ 5.0	$ 4.2	$ 3.4	$ 5.6

During the first quarter of 2007, we have contributed $10.2 million to our pension plans and $3.5 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $31 million to our pension plans in 2007 for a total of approximately $41 million. We presently anticipate making additional contributions of approximately $12 million to our other postretirement benefit plans in 2007 for a total of approximately $16 million.

Note 7. Inventories

Inventories at March 31, 2007 and December 31, 2006 are as follows:

	March 31, 2007	December 31, 2006
	(Millions)	
Natural gas liquids	$ 112.2	$ 77.9
Materials, supplies and other	90.8	82.1
Natural gas in underground storage	59.2	77.6
	$ 262.2	$ 237.6

Note 8. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At March 31, 2007, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at March 31, 2007 (Millions)
$500 million unsecured credit facilities	$ 351.0
$700 million unsecured credit facilities	$ 479.7
$1.5 billion unsecured credit facility	$ 28.0

Exploration & Production's credit agreement

In February 2007, Exploration & Production 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. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Issuances and retirements

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior unsecured notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement.

Registration payment arrangements

Under the terms of the Northwest Pipeline $185 million 5.95 percent senior unsecured notes mentioned above, Northwest Pipeline is obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes issued under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing. Northwest Pipeline may be required to provide a shelf registration statement to cover resales of the notes under certain circumstances. Northwest Pipeline may also be required to pay additional interest, up to a maximum of 0.5 percent annually, if it fails to satisfy these obligations.

On June 20, 2006, Williams Partners L.P. issued $150 million aggregate principal amount of 7.5 percent senior unsecured notes in a private debt placement. On December 13, 2006, Williams Partners L.P. issued $600 million aggregate principal amount of 7.25 percent senior unsecured notes in a private debt placement. In connection with these issuances, Williams Partners L.P. entered into registration rights agreements with the initial purchasers of the senior unsecured notes. In these agreements they agreed to conduct a registered exchange offer for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. If Williams Partners L.P. fails to initiate the exchange offers by May 30, 2007, they will be required to pay additional interest, up to a maximum of 0.5 percent annually. Williams Partners L.P. initiated exchange offers for both series on April 10, 2007.

On December 13, 2006, Williams Partners L.P. issued approximately $350 million of common and Class B units in a private equity offering. In connection with these issuances, Williams Partners L.P. entered into a registration rights agreement with the initial purchasers whereby Williams Partners L.P. agreed to file a shelf registration statement providing for the resale of the units. Additionally, the registration rights agreement provides for the registration of common units that would be issued upon conversion of the Class B units. If the shelf is unavailable for a period that exceeds an aggregate of 30 days in any 90-day period or 105 days in any 365-day period, the purchasers are entitled to receive liquidated damages. Liquidated damages are calculated as 0.25% of the Liquidated Damages Multiplier per 30-day period for the first 60 days following the 90th day, increasing by an additional 0.25% of the Liquidated Damages Multiplier per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the Liquidated Damages Multiplier per 30-day period. The Liquidated Damages Multiplier is (i) the product of $36.59 times the number of common units purchased that have not yet been resold pursuant to the registration statement plus (ii) the product of $35.81 times the number of Class B Units purchased.

As of March 31, 2007, we have not accrued any liabilities for these registration payment arrangements.

Note 9. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of March 31, 2007, which we believe is adequate for any refunds that may be required.

Issues Resulting from California Energy Crisis

Our subsidiary, Williams Power Company, Inc. (WPC), whose results of operations were included in our previously reported Power segment (see Note 3), is 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 Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a December 19, 2006, Ninth Circuit Court of Appeals decision, certain contracts that WPC entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which WPC sold electricity, totaled approximately $89 million in revenue. While WPC is not a party to the cases involved in the appellate court decision, the buyer of electricity from WPC is a party to the cases and claims that WPC 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 $21 million at March 31, 2007. 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 proceedings, 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 to the

California Attorney General (or his designee) over the next three years, with 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 WPC 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 was 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 settled this matter for $2.4 million and are awaiting the court’s approval.
- 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. The Tennessee purchasers have appealed the court’s February 2007 dismissal of the case before it. The cases in the other jurisdictions have been removed to federal court.

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 Transcontinental Gas Pipe Line Corporation’s (Transco) 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. Gas Marketing Services 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, Gas Marketing Services could have been subject to surcharges of approximately $117 million, including interest, through March 31, 2007, 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.

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 demanded repayment of the purchase price for the reduced portions of the claims. In February 2007, we completed a settlement with the purchaser covering 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 March 31, 2007, 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 March 31, 2007, 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 March 31, 2007, 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 agreed to pay a $180,000 penalty and to conduct a supplemental environmental project to upgrade our equipment. We expect that 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 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.

On April 11, 2007, the New Mexico Environment Department's Air Quality Bureau (NMED) issued a NOV to Williams Four Corners, LLC that alleges various emission and reporting violations in connection with our Lybrook gas processing plant's flare and leak detection and repair program. We are investigating the matter.

On April 16, 2007, the CDPHE issued a NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. We are investigating the matter.

On April 27, 2007, the Wyoming Department of Environmental Quality issued a NOV to Williams Production RMT Company that alleges recurring violations of various Wyoming Pollution Discharge Elimination System permits in connection with our coal bed methane gas production facilities in the state. We have begun our investigation of the matter.

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 March 31, 2007, we have accrued liabilities of approximately $9 million for such excess costs.

Other

At March 31, 2007, we have accrued environmental liabilities totaling approximately $24 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-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 court's approval of the settlement.

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 in April 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 would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. 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. 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 WPC. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. 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.

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 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. In June 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 by the end 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, WPC received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and WPC, 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 WPC jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $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 Beach's liability because the officer ruled that AES Redondo Beach is an exempt public utility. We appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES Redondo Beach. On April 11, 2007, the court ruled that we must pay the city the disputed amount of approximately $57 million by May 1, 2007, in order to pursue our appeal. On April 30, 2007, we paid the city the disputed amount. Despite the city hearing officer's unfavorable decision and the payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The city's 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 Beach have also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals. 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 WPC 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 WPC 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 $23 million, all of which have been accrued as of March 31, 2007. 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.

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 March 31, 2007.

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 ongoing mediation.

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 approximately $18.5 million in damages and our specific performance under certain guarantees. In 2006, we filed our answer to the purchaser's complaint denying all liability. We anticipate that the trial will occur in the first quarter of 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At March 31, 2007, 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.

Commitments

WPC 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 March 31, 2007, WPC's estimated committed payments under these contracts range from approximately $318 million to $425 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 $5.4 billion. These contracts are included in the pending sale of our power business to Bear Energy, LP. (See Note 3.)

Guarantees

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, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to 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 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 guaranteed commercial letters of credit totaling $20 million on behalf of a certain entity in which we have an equity ownership interest. These expire by January 2008 and have no carrying value.

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

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 $45 million at March 31, 2007. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $41 million at March 31, 2007.

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.

Note 10. Comprehensive Income

Comprehensive income is as follows:

	Three months ended March 31, 2007	2006
	(Millions)	
Net income	$ 134.0	$ 131.9
Other comprehensive income:		
Net unrealized gains on derivative instruments	10.0	189.0
Net reclassification into earnings of derivative instrument losses	9.9	101.4
Foreign currency translation adjustments	3.1	(2.2)
Minimum pension liability adjustment	—	(.3)
Pension benefits:		
Amortization of prior service credit	(.1)	—
Amortization of net actuarial loss	4.0	—
Other postretirement benefits:		
Amortization of prior service cost	.3	—
Other comprehensive income before taxes	27.2	287.9
Income tax provision on other comprehensive income	(9.3)	(111.1)
Other comprehensive income	17.9	176.8
Comprehensive income	$ 151.9	$ 308.7

Net unrealized gains on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The net unrealized gains at March 31, 2007, include net unrealized gains on forward natural gas purchases and sales of approximately $33 million, partially offset by net unrealized losses on forward power purchases and sales of approximately $23 million. The net unrealized gains at March 31, 2006, include net unrealized gains on forward natural gas purchases and sales of approximately $97 million and net unrealized gains on forward power purchases and sales of approximately $92 million.

Note 11. Segment Disclosures

On May 21, 2007, we announced that we had entered into a definitive agreement to sell substantially all of our power business to Bear Energy, LP. This pending sale has impacted our segment presentation. See Notes 2 and 3 for further discussion.

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 2.) Other primarily consists of corporate operations and our Milagro natural gas-fired electric generating plant. (See Note 3.)

Performance Measurement

We currently evaluate performance based upon *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. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Notes (Continued)

The majority of energy commodity hedging by certain of our business units was historically done through intercompany derivatives with our Gas Marketing Services segment which, in turn, entered into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bore the counterparty performance risks associated with unrelated third parties. However, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its new credit agreement. (See Note 8.)

The Gas Marketing Services segment includes the continued marketing and risk management operations that support our natural gas businesses. The operations include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing Services manages various natural gas-related contracts such as transportation, storage, and related hedges.

External revenues of our Exploration & Production segment include third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income* as reported in the Consolidated Statement of Income.

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Three months ended March 31, 2007							
Segment revenues:							
External	$ (62.4)	$ 363.0	$ 984.1	$ 1,074.3	$ 9.3	$ —	$ 2,368.3
Internal	545.1	7.8	11.3	214.0	4.3	(782.5)	—
Total revenues	$ 482.7	$ 370.8	$ 995.4	$ 1,288.3	$ 13.6	$ (782.5)	$ 2,368.3
Segment profit (loss)	$ 188.1	$ 149.7	$ 154.1	$ (29.8)	$ (.3)	$ —	$ 461.8
Less:							
Equity earnings	5.3	9.3	6.7	—	.1	—	21.4
Segment operating income (loss)	$ 182.8	$ 140.4	$ 147.4	$ (29.8)	$ (.4)	$ —	440.4
General corporate expenses							(39.4)
Consolidated operating income							$ 401.0
Three months ended March 31, 2006							
Segment revenues:							
External	$ (59.5)	$ 330.5	$ 966.1	$ 1,140.4	$ 9.6	$ —	$ 2,387.1
Internal	415.5	3.5	13.3	283.6	9.6	(725.5)	—
Total revenues	$ 356.0	$ 334.0	$ 979.4	$ 1,424.0	$ 19.2	$ (725.5)	$ 2,387.1
Segment profit (loss)	$ 147.6	$ 134.7	$ 151.3	$ (23.4)	$ .7	$ —	$ 410.9
Less:							
Equity earnings	5.0	7.5	9.7	—	—	—	22.2
Segment operating income (loss)	$ 142.6	$ 127.2	$ 141.6	$ (23.4)	$ .7	$ —	388.7
General corporate expenses							(31.8)
Consolidated operating income							$ 356.9

The following table reflects *total assets* by reporting segment.

	Total Assets	
	March 31, 2007	December 31, 2006
	(Millions)	
Exploration & Production	$ 8,442.5	$ 7,850.9
Gas Pipeline	8,368.5	8,331.7
Midstream Gas & Liquids	5,618.8	5,465.8
Gas Marketing Services (1)	6,589.0	5,519.1
Other	3,778.6	3,954.7
Eliminations (2)	(8,278.9)	(7,121.6)
	24,518.5	24,000.6
Discontinued operations	1,417.5	1,401.8
Total assets	$ 25,936.0	$ 25,402.4

(1) The increase in Gas Marketing Services' total assets is due primarily to an increase in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services' derivative assets are substantially offset by their derivative liabilities.

(2) The increase in Eliminations is due primarily to an increase in the intercompany derivative balances.

Note 12. Recent Accounting Standards

In September 2006, the FASB issued Statement of Financial Accounting Standards (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 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. On the adoption 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 continue to assess whether to apply the provisions of SFAS No. 159 to eligible financial instruments in place on the adoption date and the related impact on our Consolidated Financial Statements.

On March 29, 2007, the FERC issued "Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans." The guidance is being provided to all jurisdictional entities to ensure proper and consistent implementation of 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)" for FERC financial reporting purposes beginning with the 2007 FERC Form 2 to be filed in 2008. We are currently evaluating the impact of the FERC guidance on our Gas Pipeline segment and Consolidated Financial Statements.

In April 2007, the FASB issued a Staff Position (FSP) on a previously issued FIN, FSP FIN 39-1, "Amendment of FASB Interpretation No. 39." FSP FIN 39-1 amends FIN 39, "Offsetting of Amounts Related to Certain Contracts (as amended)" by addressing offsetting fair value amounts recognized for the right to reclaim or obligation to return cash collateral arising from derivative instruments that have been offset pursuant to a master netting arrangement. The FSP requires disclosure of the accounting policy related to offsetting fair value amounts as well as disclosure of amounts recognized for the right to reclaim or obligation to return cash collateral. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted, and is applied retrospectively as a change in accounting principle for all financial statements presented. We will assess the impact of FSP FIN 39-1 on our Consolidated Financial Statements.

ITEM 2

Management's Discussion and Analysis of Financial Condition and Results of Operations

Company Outlook

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.

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 9 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 cash equivalents and unused revolving credit facilities.

Our *income from continuing operations* for the three months ended March 31, 2007, increased $37.7 million compared to the three months ended March 31, 2006. This result is reflective of:

- Increased operating income at Exploration & Production associated with increased production and higher average net realized prices;
- Increased operating income at Gas Pipeline due to new rates that went into effect during the first quarter of 2007;
- The absence of early debt retirement costs incurred during the first quarter of 2006.

See additional discussion in Results of Operations

Our *net cash provided by operating activities* increased $135.1 million primarily due to a decrease in net cash outflows from *margin deposits and customer margin deposits payable.* See additional discussion in Management's Discussion and Analysis of Financial Condition.

Recent Events

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our current continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document [Exhibit 99.3] and our 2006 Annual Report, as revised [Exhibit 99.1 and 99.2].

Sale of Power Business

On May 21, 2007, we announced our intent to sell substantially all of our power business to Bear Energy, LP, a unit of the Bear Stearns Company, Inc. for $512 million. This pending sale reduces the risk and complexity of our overall business model and allows our ongoing efforts to focus our investment capital and growth efforts on our core natural gas businesses. The sale is expected to close in 2007.

The pending sale of our power business to Bear Energy, LP, includes tolling contracts, full requirements contracts, tolling resales, heat rate options, related hedges and other related assets including certain property and software. Our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton), is currently being marketed for sale. These operations are part of our previously reported Power segment and are now reflected in our results of operations as discontinued operations. (See Notes 2 and 3 of Notes to Consolidated Financial Statements.)

Other continuing components of our former Power segment are now being reported as follows:

- Marketing and risk management operations that support our natural gas businesses are reflected in the new Gas Marketing Services segment.
- Our equity investment in Aux Sable Liquid Products, LP (Aux Sable) is now reported within the Midstream segment.
- Our natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility), is now reported within the Other segment.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2007, compared to the three months ended March 31, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31, 2007	Three months ended March 31, 2006	$ Change from 2006 *	%Change from 2006 *
	(Millions)			
Revenues	$2,368.3	$2,387.1	-18.8	-1%
Costs and expenses:				
Costs and operating expenses	1,843.3	1,962.2	+118.9	+6%
Selling, general and administrative expenses	102.5	57.8	-44.7	-77%
Other income — net	(17.9)	(21.6)	-3.7	-17%
General corporate expenses	39.4	31.8	-7.6	-24%
Total costs and expenses	1,967.3	2,030.2		
Operating income	401.0	356.9		
Interest accrued — net	(167.1)	(158.3)	-8.8	-6%
Investing income	52.4	47.7	+4.7	+10%
Early debt retirement costs	—	(27.0)	+27.0	+100%
Minority interest in income of consolidated subsidiaries	(14.0)	(7.1)	-6.9	-97%
Other income — net	2.0	8.0	-6.0	-75%
Income from continuing operations before income taxes	274.3	220.2		
Provision for income taxes	104.6	88.2	-16.4	-19%
Income from continuing operations	169.7	132.0		
Loss from discontinued operations	(35.7)	(.1)	-35.6	NM
Net income	$ 134.0	$ 131.9		

* + = Favorable change to *net income*; – = Unfavorable change to *net income*; NM = A percentage calculation is not meaningful due to a percentage change greater than 200.

Three months ended March 31, 2007 vs. three months ended March 31, 2006

The decrease in *revenues* is primarily due to reduced natural gas sales prices at Gas Marketing Services. Additionally, the effect of a change in forward prices on legacy natural gas contracts not designated as cash flow hedges had an unfavorable impact on revenues. Partially offsetting these decreases are increased revenues at Exploration & Production due to both increased production volumes and net average realized prices. Net average realized prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

The decrease in *costs and operating expenses* is largely due to reduced natural gas purchase prices at Gas Marketing Services. Partially offsetting these decreases are 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 the absence of a 2006 gain on sale of certain receivables at Gas Marketing Services of $23.7 million and higher costs due to increased staffing in support of drilling and operational activity at Exploration & Production.

Other income — net within *operating income* in 2007 includes:

- Income of approximately $8 million due to the reversal of a planned major maintenance accrual (see further discussion in Midstream's Results of Operations);
- Net gains of approximately $6 million on foreign currency exchanges, primarily at Midstream.

Other income — net within *operating income* in 2006 includes:

- Income of $9 million due to a settlement of an international contract dispute at Midstream;
- An approximate $4 million gain on sale of idle gas treating equipment at Midstream;
- An approximate $4 million favorable transportation settlement at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher information technology, consulting and insurance costs.

Interest accrued — net increased primarily due to changes in our debt portfolio, most significantly the issuance of new debt in 2006 by Williams Partners L.P., our consolidated master limited partnership.

Investing income increased primarily due to increased interest income associated with larger cash and cash equivalent balances combined with higher rates of return, partially offset by the absence of an approximate $7 million gain on sale of an international investment in 2006.

Early debt retirement costs in first quarter 2006 includes $25.8 million in premiums and $1.2 million in fees related to the January 2006 debt conversion. (See Note 4 of Notes to Consolidated Financial Statements.)

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

Provision for income taxes was unfavorable primarily due to increased pre-tax income. The effective tax rate for the three months ended March 31, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and net foreign operations. The effective tax rate for the three months ended March 31, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes.

Loss from discontinued operations includes results related to our discontinued power business. (See Note 3 of Notes to Consolidated Financial Statements.)

Results of Operations — Segments

Exploration & Production

Overview of Three Months Ended March 31, 2007

During the first three months of 2007, we continued our strategy of a rapid execution of our development drilling program in our growth basins. Accordingly, we:

- Increased average daily domestic production levels by approximately 28 percent compared to the first three months of 2006. The average daily domestic production for the first three months was approximately 845 million cubic feet of gas equivalent (MMcfe) in 2007 compared to 661 MMcfe in 2006. The increased production is primarily due to increased development within the Piceance and Powder River basins.
- Increased capital expenditures for domestic drilling, development, and acquisition activity in the first three months of 2007 by approximately $30 million compared to 2006.

The benefits of higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to higher well service and industry costs and increased production volumes.

Significant events

In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging and on natural gas reserves value. (See Note 8 of Notes to Consolidated Financial Statements.)

We may also execute hedges with the Gas Marketing Services segment which, in turn, executes offsetting derivative contracts with unrelated third parties. In this situation, Gas Marketing Services, generally, bears the counterparty performance risks associated with unrelated third parties. Hedging decisions primarily are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

During the first three months of 2007, we entered into various derivative collar agreements at the basin level which, in the aggregate, hedge an additional 80 MMcfe per day for production in 2008 and 90 MMcfe per day for production in 2009.

Outlook for the Remainder of 2007

Our expectations for the remainder of the year include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through our remaining planned capital expenditures projected between $1 and $1.1 billion.
- Continuing to grow our average daily domestic production level with a goal of 10 to 20 percent growth compared to 2006.

Approximately 172 MMcfe per day of our forecasted 2007 daily production is hedged by NYMEX and basis fixed-price contracts at prices that average $3.89 per Mcfe at a basin level. In addition, we have collar agreements for each month remaining 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 77 MMcfe per day at a weighted average floor price of $6.82 per Mcfe and a weighted average ceiling price of $10.75 per Mcfe at a basin level.

Risks to achieving our expectations include weather conditions at certain of our locations, obtaining permits as planned for drilling, and market price movements.

Period-Over-Period Results

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Segment revenues	$ 482.7	$ 356.0
Segment profit	$ 188.1	$ 147.6

Three months ended March 31, 2007 vs. three months ended March 31, 2006

Total *segment revenues* increased $126.7 million, or 36 percent, primarily due to the following:

- $126 million, or 44 percent, increase in domestic production revenues reflecting $80 million higher revenues associated with a 28 percent increase in production volumes sold and $46 million higher revenues associated with a 13 percent increase in net realized average prices. The increase in production volumes was from primarily the Piceance and Powder River basins. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.
- $26 million increase in revenues for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*.
- The absence in 2007 of $9 million of unrealized gains from hedge ineffectiveness in the first quarter of 2006.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production. Approximately 20 percent of domestic production in the first quarter of 2007 was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.94 per Mcfe at a basin level compared to 44 percent hedged at a weighted-average price of $3.80 per Mcfe for the same period in 2006. Also in the first quarter of 2007, approximately 32 percent of domestic production was hedged in the collar agreements previously discussed in the Outlook section compared to 17 percent hedged in various collar agreements in the first quarter of 2006.

Total *segment costs and expenses* increased $87 million, primarily due to the following:

- $41 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;
- $26 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues;*
- $14 million higher lease operating expense from the increased number of producing wells and higher well service and industry costs;
- $14 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity including higher compensation. In addition, we incurred higher legal, insurance, and information technology support costs also related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods.

First quarter 2006 *segment costs and expenses* do not include approximately $6 million in lease operating expenses related to that period. The amount was recorded in the second quarter of 2006.

The $40.5 million increase in *segment profit* is primarily due to the approximately 28 percent increase in production volumes sold and higher net realized average prices. Partially offsetting this increase are higher *segment costs and expenses* as previously discussed.

Gas Pipeline

Overview of Three Months Ended March 31, 2007

Status 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, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco. We expect the new rates to result in significantly higher revenues.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline's system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

Outlook for the Remainder of 2007

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 May 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. 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 April 2007, we received FERC approval to expand Transco's existing facilities in the Mid-Atlantic region of the United States by constructing 16.4 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.

Period-Over-Period Results

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Segment revenues	$ 370.8	$ 334.0
Segment profit	$ 149.7	$ 134.7

Three months ended March 31, 2007 vs. three months ended March 31, 2006

Revenues increased $36.8 million, or 11 percent, due primarily to a $30 million increase in transportation revenue and a $3 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $3 million due to exchange imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses increased $18 million, or 10 percent, due primarily to:

- An increase in depreciation expense of $7 million due to property additions;
- An increase in personnel costs of $4 million;
- The absence of a $3 million credit to expense recorded in 2006 related to corrections of the carrying value of certain liabilities;
- An increase in costs of $3 million associated with exchange imbalance settlements (offset in *revenues*).

SG&A expenses increased $4 million, or 12 percent, due primarily to a $5 million increase in property insurance expenses resulting from increased premiums on offshore facilities and a $2 million increase in information systems support costs. Partially offsetting these increases is a $5 million decrease in expense related to an adjustment to correct rent expense from prior periods.

The $15 million, or 11 percent, increase in *segment profit* is due primarily to $36.8 million higher revenues as previously discussed, partially offset by increases in *costs and operating expenses* and *SG&A expenses* as previously discussed.

Midstream Gas & Liquids

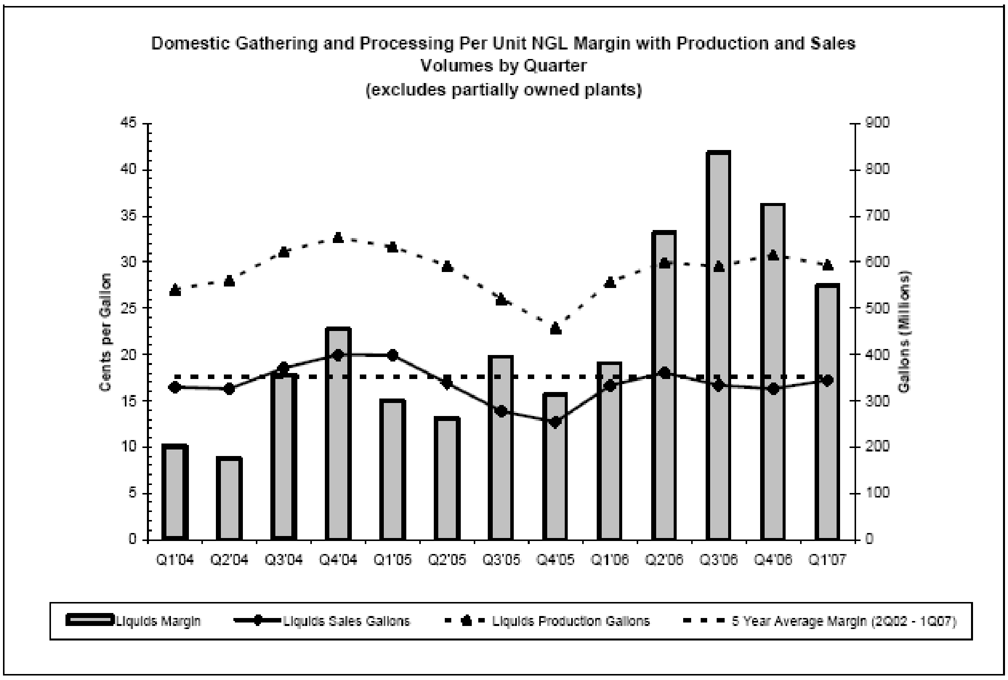
Overview of Three Months Ended March 31, 2007

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 the first three months of 2007 include the following:

Continued favorable commodity price margins

The actual realized natural gas liquid (NGL) per unit margins at our processing plants exceeded Midstream's rolling five-year average for the first three months of 2007. 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 and continuing through the first quarter of 2007, NGL production rebounded from levels experienced in fourth-quarter 2005 in response to improved gas processing spreads.



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.

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion was operational for approximately half of the quarter. We also have several expansion projects ongoing in the West region to lower field pressures and increase production volumes for our customers who continue robust drilling activities in the region.

In the first quarter of 2007, we began pre-construction activities on the proposed Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. Additionally, we intend to expand 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.

In March 2007, we announced plans to construct and operate a 450 MMcf/d natural gas processing plant in western Colorado's Piceance basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. Exploration & Production's existing Piceance basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the Willow Creek facility will recover an additional 20,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

Outlook for the Remainder of 2007

The following factors could impact our business in the remaining three quarters of 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 five 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, along with political instability in many of the key oil producing countries, currently support NGL margins continuing to exceed our rolling five-year average. As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies.
- Margins in our olefins unit are highly dependent upon continued economic growth within the United States and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the United States. Based on recent market price forecasts, we anticipate olefins unit margins to be at or slightly above 2006 levels.
- Gathering and processing revenues at our facilities are expected to be at 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 continued construction of 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.
- 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 we expand our Devil's Tower infrastructure to serve the Blind Faith prospect.
- We are currently negotiating with our customer in Venezuela to resolve approximately $16 million in past due invoices, before associated reserves, 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 an inequitable 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, escalating our concern regarding political risk in Venezuela.
- We are conducting negotiations with the Jicarilla Apache Nation in northern New Mexico for the renewal of certain rights of way on reservation lands. The current right of way agreement, which covers certain gathering system assets in our West region, expired on December 31, 2006. We continue to operate our assets on these reservation lands pursuant to a special business license which lasts through June 30, 2007, while we conduct further discussions that could result in renewal of our rights of way, sale of the gathering assets on reservation lands or other options that might be in the mutual interest of both parties.

Period-Over-Period Results

	Three months ended March 31, 2007	2006
	(Millions)	
Segment revenues	$ 995.4	$ 979.4
Segment profit		
Domestic gathering & processing	$ 123.4	$ 123.4
Venezuela	26.9	35.5
Other	24.7	7.3
Indirect general and administrative expense	(20.9)	(14.9)
Total	$ 154.1	$ 151.3

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.

Three months ended March 31, 2007 vs. three months ended March 31, 2006

The $16 million increase in *segment revenues* is largely due to a $50 million increase in the marketing of NGLs and olefins.

This increase was partially offset by:

- A $19 million decrease in revenues from our olefins unit due primarily to a planned shut down of our Geismar ethane cracker for major maintenance;
- A $5 million decrease in fee revenues including an $11 million decrease in deepwater gathering and production handling volumes, partially offset by an increase in other fee revenues;
- A $10 million decrease in revenues associated with the production of NGLs and condensate.

Segment costs and expenses increased $10 million primarily as a result of:

- A $37 million increase in NGL and olefin marketing purchases;
- A $22 million increase in operating expenses including higher property insurance, gathering and plant fuel, and depreciation;
- A $4 million increase in general and administrative costs due primarily to higher legal, information technology and consulting expenses.

These increases were partially offset by:

- A $37 million decrease in costs associated with the production of NGLs and condensate due primarily to lower natural gas prices;
- A $19 million decrease in costs associated with production in our olefins unit due to the planned shut down mentioned above.

The $2.8 million increase in Midstream's *segment profit* reflects higher NGL margins and higher margins related to the marketing of NGLs and olefins, partially offset by higher operating expenses. A more detailed analysis of the segment profit of Midstream's various operations is presented as follows.

Domestic gathering & processing

The *domestic gathering and processing segment profit* is unchanged and includes a $19 million increase in the West region and a $19 million decrease in the Gulf Coast region.

The $19 million increase in our West region's *segment profit* primarily results from higher product margins and higher gathering and processing fee based revenues, partially offset by higher operating expenses and lower gains on the sale of assets. The significant components of this increase include the following:

- NGL and condensate margins increased $33 million in the first quarter of 2007 compared to the same period in 2006. This increase was driven by a decrease in costs associated with the production of NGLs reflecting lower natural gas prices and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant, partially offset by a decrease in average per unit NGL prices. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense.
- Gathering and processing fee revenues increased $3 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees. Gathering fees are higher as a result of higher average per-unit gathering rates.
- Operating expenses increased $13 million including $7 million in higher gathering and plant fuel due primarily to the expiration of a favorable gas purchase contract, $4 million in higher depreciation, $3 million in lower gas imbalance revaluation gains, and $2 million in higher operations and maintenance expenses, partially offset by $3 million in lower system losses.
- The first quarter of 2006 included a $4 million gain on the sale of idle gas treating equipment.

The $19 million decrease in the Gulf Coast region's *segment profit* is primarily a result of lower volumes from our deepwater facilities, lower NGL margins and higher operating expenses. The significant components of this increase include the following:

- NGL margins decreased $6 million driven by a decrease in volumes resulting from lower NGL recoveries during the first quarter of 2007 caused by intermittent periods of uneconomical market commodity prices for ethane, partially offset by a decrease in costs associated with the production of NGLs.
- Fee revenues from our deepwater assets decreased $11 million due primarily to higher than normal production flowing across our Devils Tower facility in the first quarter of 2006 driven by the initial flows from the Goldfinger and Triton fields and other volume declines.
- Operating expenses increased $4 million primarily as a result of higher property insurance costs.

Venezuela

Segment profit for our Venezuela assets decreased $8.6 million. The decrease is primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006, partially offset by $7 million of currency exchange gains in 2007. In addition, revenues and equity earnings are lower and operating expenses are slightly higher.

Other

The $17.4 million increase in *segment profit* of our other operations is due primarily to $5 million in higher margins related to the marketing of olefins, $8 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006, an $8 million reversal of a maintenance accrual (see below), partially offset by the absence of a $4 million favorable transportation settlement in 2006.

Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The $6 million increase in indirect general and administrative expense is due primarily to higher employee, consulting, and legal expenses.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, which were part of our former Power segment, including certain legacy natural gas contracts and positions.

Overview of Three Months Ended March 31, 2007

Gas Marketing's operating results for the first three months of 2007 reflect unrealized mark-to-market losses primarily caused by an increase in forward natural gas prices against a net short derivative legacy position. Most of these derivative positions are economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

Outlook for the Remainder of 2007

For the remainder of 2007, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment are included in the Gas Marketing segment. We intend to manage or liquidate a substantial portion of these legacy contracts in order to reduce risk and volatility.

Until such legacy positions are liquidated, Gas Marketing's earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but do not qualify for hedge accounting or are not designated as hedges for accounting purposes.

Period-Over-Period Results

	Three months ended March 31,	
	2007	**2006**
	(Millions)	
Realized revenues	$ 1,328.5	$ 1,452.1
Net forward unrealized mark-to-market losses	(40.2)	(28.1)
Segment revenues	1,288.3	1,424.0
Costs and operating expenses	1,316.2	1,469.6
Gross margin	(27.9)	(45.6)
Selling, general and administrative (income) expense	1.9	(20.9)
Other income—net	—	(1.3)
Segment loss	$ (29.8)	$ (23.4)

Three months ended March 31, 2007 vs. three months ended March 31, 2006

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. *Realized revenues* decreased $123.6 million primarily due to a 16 percent decrease in average natural gas sales prices, partially offset by an 11 percent increase in natural gas sales volumes.

Net forward unrealized mark-to-market losses primarily represent changes in the fair values of certain legacy derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The effect of changes in forward prices and portfolio position on legacy natural gas derivative contracts primarily caused the $12.1 million unfavorable change in *net forward unrealized mark-to-market losses.* An increase in forward natural gas prices in 2007 caused losses on legacy net forward gas fixed-price sales contracts. A decrease in forward natural gas prices in 2006 caused lesser losses on legacy net forward gas fixed-price purchase contracts.

The $153.4 million decrease in Gas Marketing's *costs and operating expenses* was primarily due to a 16 percent decrease in average natural gas purchase prices.

The unfavorable change in Gas Marketing's *selling, general and administrative (income) expense* in the first quarter of 2007 is primarily due to the absence of a $23.7 million gain from the sale of certain receivables to a third party in first-quarter 2006.

The effect of a change in forward prices on legacy natural gas derivative contracts and the unfavorable change in *SG&A (income) expense*, partially offset by an improvement in accrual gross margin (defined as *realized revenues* less *costs and operating expenses*), primarily caused the $6.4 million increase in *segment loss.*

Other

Period-Over-Period Results

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Segment revenues	$ 13.6	$ 19.2
Segment profit (loss)	$ (.3)	$ .7

As previously discussed, our natural gas-fired electric generating plant near Bloomfield, New Mexico (Milagro facility), is now reported within the Other segment. (See Note 3 of Notes to Consolidated Financial Statements.) The results of our Other segment are relatively comparable to the prior year.

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 March 31, 2007. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 3 of Notes to Consolidated Financial Statements.)

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
$ 14	$ 1	$ (1)	$ (1)	$ —	$ 13

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 Exploration & Production's forecasted sales of natural gas production and certain forecasted purchases of gas and purchases and sales of power related to our former Power segment's long-term structured contracts and owned generation under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $225 million as of March 31, 2007, which includes the existing fair value of the derivatives at the time of their designation as SFAS 133 cash flow hedges. The chart below reflects the fair value of derivatives held for nontrading purposes as of March 31, 2007, for Gas Marketing Services, Exploration & Production, Midstream, Other, and nontrading derivatives reported in assets and liabilities of discontinued operations.

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
$ 41	$ 215	$ 88	$ 31	$ —	$ 375

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 March 31, 2007, we held collateral support, including letters of credit, of $613 million.

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations as of March 31, 2007 (see Note 3 of Notes to Consolidated Financial Statements), is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 342.1	$ 344.0
Energy marketers and traders	468.2	2,094.8
Financial institutions	2,347.9	2,347.9
Other	21.7	25.5
	$ 3,179.9	4,812.2
Credit reserves		(15.9)
Gross credit exposure from derivatives		$4,796.3

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 March 31, 2007, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 146.3	$ 147.0
Energy marketers and traders	159.2	404.0
Financial institutions	197.6	197.6
Other	1.3	1.3
	$ 504.4	749.9
Credit reserves		(15.9)
Net credit exposure from derivatives		$ 734.0

(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.

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. For the remainder of 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 entered 2007 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

- Exploration & Production will continue its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.
- 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 $2.4 billion to $2.6 billion in 2007, with approximately $1.9 billion to $2.1 billion to be incurred over the remainder of the year. 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 compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

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

- Lower than expected levels of cash flow from operations 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 remaining expected 2007 production. In addition, Exploration & Production has collar agreements for each month of 2007 which hedge approximately 272 MMcfe per day of remaining expected 2007 production. Also, our former power business has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010. These sales contracts and related fixed demand obligations are included in the anticipated sale of substantially all of our power business.
- Sensitivity of margin requirements associated with our marginable commodity contracts. As of March 31, 2007, we estimate our exposure to additional margin requirements through the remainder of 2007 to be no more than $498 million, using a statistical analysis at a 99 percent confidence level.
- Exposure associated with our efforts to resolve regulatory and litigation issues. (See Note 9 of Notes to Consolidated Financial Statements.)

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. (See Note 8 of Notes to Consolidated Financial Statements.)

Overview

In February 2007, Exploration & Production 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. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Credit ratings

On March 19, 2007, Standard & Poor's raised our senior unsecured debt rating from a BB— to a BB with a stable ratings outlook. With respect to Standard & Poor's, a rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify it's ratings with a "+" or a "—" sign to show the obligor's relative standing within a major rating category.

Moody's Investors Service rates our senior unsecured debt at 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.

Fitch Ratings rates our senior unsecured debt at a 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.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others 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

	March 31, 2007 (Millions)
Cash and cash equivalents*	$ 1,811.2
Auction rate securities and other liquid securities	234.7
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	369.3
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,472.0
	$ 3,887.2

* *Cash and cash equivalents* includes $203.5 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 $528 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. If the credit rating of Northwest Pipeline or Transco is below investment grade for all credit rating agencies, 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.

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. (See Note 8 of Notes to Consolidated Financial Statements.)

Sources (Uses) of Cash

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 299.8	$ 164.7
Financing activities	(116.1)	(155.8)
Investing activities	(641.1)	(491.1)
Decrease in cash and cash equivalents	$ (457.4)	$ (482.2)

Operating activities

Our *net cash provided by operating activities* for the three months ended March 31, 2007 increased from the same period in 2006. The increase in *net cash provided by operating activities* is largely due to a change in working capital, which is primarily due to a decrease in net cash outflows from *margin deposits and customer margin deposits payable* due mostly to changes in natural gas prices and our marginable positions.

Financing activities

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

During the first quarter of 2007, we paid a quarterly dividend of 9 cents per common share, totaling $54.1 million, compared to a quarterly dividend of 7.5 cents per common share, totaling $44.6 million, for the first quarter of 2006.

Investing activities

During the first three months of 2007, capital expenditures totaled $509.1 million and were primarily related to Exploration & Production's increased drilling activity, mostly in the Piceance basin.

During the first three months of 2007, we purchased $173.2 million and received $44.6 million from the sale of auction rate securities. These are utilized as a component of our overall cash management program.

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

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 Note 9 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.

Item 3

Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first three months of 2007. See Note 8 of Notes to Consolidated Financial Statements.

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 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. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations. Our value at risk for contracts held for trading purposes was approximately $2 million at March 31, 2007, and $1 million at December 31, 2006.

Nontrading

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

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

Our assets and liabilities of discontinued operations also include derivative contracts that hedge or could potentially hedge the commodity price risk exposure from natural gas purchases and electricity purchases and sales.

The value at risk for derivative contracts held for nontrading purposes was $13 million at March 31, 2007, and $12 million at December 31, 2006. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations. Under our agreement to sell our power business to Bear Energy, LP, for $512 million, this amount will be reduced by expected net portfolio cash flows from an April 1, 2007, valuation date through the transaction closing date. Mark-to-market gains and losses between this valuation date and the close of the transaction will not impact the economic value of the sale, although they may change the recorded gain or loss on the sale as derivative assets and liabilities included in the sale continue to be valued at fair value.

Certain of the other 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 changes in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.