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): February 23, 2005

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))

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Item 2.02. Results of Operations and Financial Condition.

On February 23, 2005, The Williams Companies, Inc. (“Williams” or the “Company”) issued a press release announcing its financial results for the quarter and year ended December 31, 2004. A copy of the press release and its accompanying financial highlights and reconciliation schedules are furnished as a part of this current report on Form 8-K as Exhibit 99.1 and is incorporated herein in its entirety by reference.

The press release and accompanying financial highlights and reconciliation schedules are being furnished pursuant to Item 2.02, Results of Operations and Financial Condition. The information furnished is not deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 8.01. Other Events.

Williams wishes to disclose for Regulation FD purposes its slide presentation, furnished herewith as Exhibit 99.2, to be utilized during a public conference call and webcast on the morning of February 23, 2005.

On February 23, 2005, Williams also announced that its domestic and international proved natural gas reserves as of December 31, 2004, increased to 3.2 trillion cubic feet equivalent. Williams replaced its 2004 U.S. natural gas production of 191 billion cubic feet equivalent at a ratio of 248 percent. A copy of the press release announcing the same is furnished as Exhibit 99.3 to this Current Report on Form 8-K and is incorporated herein.

The slide presentation and press release are being furnished pursuant to Item 8.01, Other Events. The information furnished is not deemed “filed” for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, is not subject to the liabilities of that section and is not deemed incorporated by reference in any filing under the Securities Act of 1933, as amended.

Item 9.01. Financial Statements and Exhibits.

(a) None
(b) None
(c) Exhibits

Exhibit 99.1	Copy of Williams’ press release dated February 23, 2005, publicly announcing its fourth quarter and year-end 2004 financial results.
Exhibit 99.2	Copy of Williams’ slide presentation to be utilized during the February 23, 2005, public conference call and webcast.
Exhibit 99.3	Copy of Williams’ press release dated February 23, 2005, publicly announcing its replacement of 2004 U.S. natural gas production.

Pursuant to the requirements of the Securities Exchange Act of 1934, Williams has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE WILLIAMS COMPANIES, INC.

Date: February 23, 2005

/s/ Donald R. Chappel

Name: Donald R. Chappel
Title: Senior Vice President and Chief Financial Officer

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
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Exhibit 99.1

NewsRelease

NYSE: WMB

Date: Feb. 23, 2005

Williams Reports Unaudited Fourth-Quarter and Full-Year 2004 Financial Results

- *Businesses Demonstrate Strong Performance*
- *Businesses Generate Nearly $1.5 Billion in Net Cash From Operating Activities*
- *Debt Reduced by $4 Billion*
- *Guidance Provided Through 2007*

Summary Financial Information

	2004				2003			
	4Q		Full Year		4Q		Full Year	
	millions	per share	millions	per share	millions	per share	millions	per share
Income (loss) from continuing operations	$ 95.5	$ 0.17	$ 93.2	$ 0.18	$ (73.3)	$ (0.14)	$ (57.5)	$ (0.17)
Income (loss) from discontinued operations	(22.1)	(0.04)	70.5	0.13	19.6	0.04	326.6	0.63
Net income (loss)	73.4	0.13	163.7	0.31	(53.7)	(0.10)	(492.2)	(1.01)
Recurring income (loss) from continuing operations*	68.0	0.12	261.5	0.49	57.5	0.11	(15.8)	(0.03)
Recurring income (loss) from continuing operations — after MTM adjustment*	$ 51.0	$ 0.09	$ 190.0	$ 0.35	$ 22.0	$ 0.04	$ (170.0)	$ (0.33)

*A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations and mark-to-market adjustments is available on Williams' web site at www.williams.com.

TULSA, Okla. – Williams (NYSE:WMB) announced 2004 unaudited net income of $163.7 million, or 31 cents per share on a diluted basis, compared with a net loss of $492.2 million, or a loss of $1.01 per share, for 2003.

Results for 2003 were reduced by an after-tax charge of $761.3 million, or $1.47 per share, primarily to reflect the cumulative effect of adopting the mandated accounting standard for contracts involved in energy trading and risk management activities.

For fourth-quarter 2004, the company reported net income of $73.4 million, or 13 cents per share on a diluted basis, compared with a net loss of $53.7 million, or a loss of 10 cents per share, for fourth-quarter 2003.

The company reported 2004 income from continuing operations of $93.2 million, or 18 cents per share on a diluted basis, compared with a loss of $57.5 million, or a loss of 17 cents per share, in 2003 on a restated basis.

The improvement in continuing operations over last year reflects the benefit of higher operating results, particularly in Midstream, and lower levels of interest expense primarily reflecting reduced levels of debt. The improvement was partially offset by $282.1 million in pre-tax charges for costs associated with the early retirement of debt, compared with $66.8 million for similar charges in 2003. With regard to unrealized mark-to-market gains or losses from the Power business, 2004 included a pre-tax gain of $304 million vs. a pre-tax gain of $262 million in 2003.

For fourth-quarter 2004, the company reported income from continuing operations of $95.5 million, or 17 cents per share on a diluted basis, compared with a loss of $73.3 million, or a loss of 14 cents per share, for fourth-quarter 2003 on a restated basis.

Results for fourth-quarter 2004 include a $103 million pre-tax gain and related interest associated with an insurance arbitration award at Midstream, while the same period in 2003 includes impairment charges of $89.1 million at Power. With regard to unrealized mark-to-market gains or losses from the Power business, the 2004 quarter included a pre-tax gain of $23 million vs. a pre-tax gain of $85 million in the 2003 quarter.

Income from discontinued operations for 2004 was $70.5 million, or 13 cents per share on a diluted basis, compared with income of $326.6 million, or 63 cents per share, for 2003 on a restated basis. Results for both periods largely reflect net gains from asset sales.

For fourth-quarter 2004, the company reported a loss from discontinued operations of $22.1 million, or a loss of 4 cents per share on a diluted basis, compared with income of $19.6 million, or 4 cents per share, for fourth-quarter 2003 on a restated basis.

CEO Perspective

"The successful execution of our business plan is producing benefits that we'll realize for years to come," said Steve Malcolm, chairman, president and chief executive officer.

"Over the past year, we have rapidly increased our drilling and production, dramatically reduced our debt and nearly doubled our net cash provided by operating activities.

"These kinds of drivers enabled us to reward our shareholders with a five-fold dividend increase in the fourth quarter.

"Our financial discipline and our focus on natural gas have served us well and can take us even further. Williams is positioned for continued growth and value creation."

Recurring Results

Recurring income from continuing operations – which excludes items of income or loss that the company characterizes as unrepresentative of its ongoing operations – was $261.5 million, or 49 cents per share, for 2004. In 2003, recurring results from continuing operations reflected a loss of $15.8 million on a restated basis, or a loss of 3 cents per share.

For fourth-quarter 2004, recurring income from continuing operations was $68.0 million, or 12 cents per share, compared with recurring income of $57.5 million, or 11 cents per share, for fourth-quarter 2003 on a restated basis.

A reconciliation of the company's income from continuing operations – a generally accepted accounting principles measure – to its recurring results accompanies this news release.

Recurring Results Adjusted for Residual Effect of Mark-to-Market Accounting

With the company's September decision to retain the Power business, the unit qualified for and elected to apply hedge accounting on a prospective basis beginning Oct. 1, 2004, for certain qualifying derivative contracts. Not all of Power's derivative contracts will qualify for hedge accounting.

Prior to the adoption of hedge accounting, Power accounted for its derivatives portfolio, which includes economic hedges on underlying tolling and other structured non-derivative contracts, on a mark-to-market basis. As a result, changes in fair value of its derivative portfolio over this time period have been recognized in earnings.

As a result of applying hedge accounting Oct. 1, Power's future results associated with contracts in the derivative portfolio should be less volatile. However, the residual mark-to-market effects will negatively impact reported results in future periods, serving to increase the difference between reported results and cash flows for several years.

The expected cash flows and economic value of Power's portfolio are not affected by the accounting election.

To provide an added level of disclosure and transparency, Williams is providing an analysis of recurring earnings adjusted for all of Power's mark-to-market effects. This measure was first introduced in third-quarter 2004 results.

Recurring income from continuing operations – after adjusting for the mark-to-market impact to reflect income as though mark-to-market accounting had never been applied to Power's designated hedges and other derivatives – was $190 million, or 35 cents per share, for 2004. In 2003, recurring results from continuing operations reflected a loss of $170 million, or a loss of 33 cents per share, after adjusting for the impact of mark-to-market accounting.

For fourth-quarter 2004, recurring income from continuing operations – after adjusting for the mark-to-market impact to reflect income as though mark-to-market accounting had never been applied to Power's designated hedges and other derivatives – was $51 million, or 9 cents per share, compared with recurring income of $22 million, or 4 cents per share, for fourth-quarter 2003 after adjusting for the impact of mark-to-market accounting.

A reconciliation of the company's income from continuing operations on a recurring basis to its recurring results that have been adjusted for the impact of mark-to-market accounting accompanies this news release.

Cash and Debt: Company Ends 2004 with Available Liquidity of $1.8 Billion

Williams reduced its debt by approximately $4 billion in 2004 through scheduled maturities, early debt retirements and exchanges.

At Dec. 31, 2004, Williams' total outstanding debt was approximately $8 billion. Of this amount, approximately $247 million matures in 2005, $119 million matures in 2006, and $396 million matures in 2007. Williams has already retired $200 million of the 2005 maturities.

Williams had unrestricted cash and cash equivalents of approximately $930 million at year-end 2004. At Dec. 31, Williams also had $881 million in unused and available revolving credit facilities, which are used primarily for issuing letters of credit and for liquidity.

Net cash provided by operating activities for 2004 was approximately $1.5 billion, including $16 million from discontinued operations. For 2003, net cash provided by operating activities was $770 million, including $182 million from discontinued operations on a restated basis.

Business Segment Performance

Williams' primary businesses – Exploration & Production, Midstream Gas & Liquids, Gas Pipeline and Power – reported combined segment profit of $1.45 billion in 2004. A year ago, these businesses reported consolidated segment profit of $1.29 billion on a restated basis.

In the fourth quarter of 2004, the four major businesses reported combined segment profit of $419 million vs. $161.1 million for the same period in 2003 on a restated basis.

Exploration & Production: Production Volume Growth Continues

Exploration & Production, which includes natural gas production and development in the U.S. Rocky Mountains, San Juan Basin and Midcontinent, and oil and gas development in South America, reported 2004 segment profit of $235.8 million.

A year ago, the business reported segment profit of $401.4 million. The decrease in segment profit is due primarily to the absence of $95 million in gains on the sale of assets in 2003, $24 million in lower income on derivative instruments that did not qualify for hedge accounting, and a $15.4 million loss provision in 2004 regarding an ownership dispute on prior period production. The benefit of higher production volumes was more than offset by decreased net realized average prices from hedging activities and increased operating expenses.

For the fourth quarter of 2004, Exploration & Production reported segment profit of $70.9 million vs. $50.1 million for the same period last year.

Fourth-quarter 2004 results increased primarily from the benefit of higher production volumes and higher net realized average prices.

Average daily production volumes have increased 25 percent since the fourth quarter of 2003. In the fourth quarter of 2004, average daily production from domestic and international interests was approximately 612 million cubic feet of gas equivalent, compared with 491 million cubic feet of gas equivalent during the fourth quarter of 2003.

In the fourth quarter of 2004, average daily production in the Piceance basin was 255 million cubic feet of gas equivalent. This was an increase of 5 percent vs. third-quarter average daily production of 242 million cubic feet of gas equivalent in the Piceance.

Overall, Piceance production has increased 61 percent since the fourth quarter of 2003, when average daily production was 158 million cubic feet of gas equivalent. Williams considers the Piceance basin to be its cornerstone property for production growth.

Earlier today, Williams announced year-end 2004 proved U.S. natural gas reserves of 3.0 trillion cubic feet equivalent, up 10.5 percent from year-end 2003. Including its international interests, Williams has total proved natural gas and oil reserves of 3.2 trillion cubic feet equivalent.

Domestic reserve net additions of 451 billion cubic feet equivalent exceeded last year's 408 billion cubic feet in net additions.

In 2004, Williams had a drilling success rate of approximately 99 percent. The company drilled 1,395 gross wells, of which 1,384 were successful. In 2003, Williams also achieved a 99 percent success rate, drilling 900 gross wells, of which 891 were successful.

Williams plans to invest $500 million to $575 million in capital spending in Exploration & Production in 2005; $525 million to $625 million in 2006; and $525 million to $675 million in 2007.

These investments are focused on increasing production from the company's large portfolio of undeveloped reserves and pursuing expansion opportunities in existing and new basins.

For 2005, Williams expects $400 million to $475 million in segment profit from Exploration & Production.

Midstream Gas & Liquids: Strong Margins Drive Record Quarter

Midstream, which provides gathering, processing, natural gas liquids fractionation and storage services, reported 2004 segment profit of $549.7 million.

A year ago, Midstream reported segment profit of $197.3 million on a restated basis. The increase in segment profit for 2004 reflects the benefit of significantly higher natural gas liquids production volumes and margins, higher olefins fractionation margins, a $93.6 million gain from a fourth-quarter insurance arbitration award associated with Gulf Liquids and the absence of $108.7 million of impairment charges in 2003 related to these same assets.

In the fourth quarter, Midstream reclassified Gulf Liquids results for current and prior periods to continuing operations after considering recently issued accounting guidance for the reporting of discontinued operations. Williams has previously announced its intention to divest Gulf Liquids.

For the fourth quarter of 2004, Midstream reported segment profit of $235.7 million vs. a restated $63.8 million for the same period last year.

The increase in fourth-quarter 2004 segment profit primarily is due to higher natural gas liquids and olefins production margins, as well as the $93.6 million gain on the insurance arbitration award.

In 2004, Williams completed more than 500 well connections to the company's natural gas gathering systems in Wyoming and New Mexico.

Williams plans to invest $120 million to $140 million in capital spending in Midstream in 2005; $110 million to $130 million in 2006; and $100 million to $130 million in 2007.

These investments are focused on attracting new volumes to the company's assets and further expanding Midstream's systems in existing basins.

For 2005, Williams expects $350 million to $430 million in segment profit from Midstream Gas & Liquids. The projected decline vs. 2004 results reflects an assumption that 2005 natural gas liquids margins will not reach the record levels achieved in 2004.

Gas Pipeline: Unit Posts Best Quarter for all of 2003 and 2004

Gas Pipeline, which provides natural gas transportation and storage services primarily in the Northwest and along the Eastern Seaboard, reported 2004 segment profit of $585.8 million.

A year ago, Gas Pipeline reported segment profit of $555.5 million on a restated basis. The increase in 2004 segment profit reflects higher equity earnings from Williams' investment in the Gulfstream system and the absence of a 2003 charge of $25.6 million to write-off certain capitalized software development costs.

The benefit of increased revenues associated with expansion projects was offset by lower commodity and short-term firm revenues, increased maintenance expense and costs to comply with new pipeline safety requirements and a $9 million charge in 2004 to write-off previously capitalized costs associated with an idled segment of the Northwest Pipeline system.

For the fourth-quarter of 2004, Gas Pipeline reported segment profit of $156.8 million vs. a restated $148.2 million for the same period last year. The increase reflects the benefit of expansion projects and higher equity earnings from the Gulfstream investment. The 2004 period represents the highest quarterly segment profit for Gas Pipeline in 2003 and 2004.

In November, Williams completed a new natural gas pipeline lateral near Everett, Wash., on Northwest Pipeline. The new 9-mile segment, known as the Everett Delta project, provides an additional 113,000 dekatherms per day of natural gas to a customer.

In December, the Transco system established a one-day throughput record of 8.73 million dekatherms. The previous high of 8.34 million dekatherms occurred in 2003.

Williams also filed an application with the Federal Energy Regulatory Commission in the fourth quarter to construct a $333 million project in western Washington in 2006. This is designed to permanently replace most of the 360,000 dekatherms per day of capacity on the Northwest system that was idled in December 2003. Approximately 131,000 dekatherms per day of service were restored on a temporary basis during the second quarter of 2004.

Williams plans to invest $370 million to $420 million in capital spending in Gas Pipeline in 2005; $475 million to $550 million in 2006; and $250 million to $325 million in 2007.

These investments are focused on maintenance, regulatory compliance, the capacity replacement project on Northwest Pipeline, and incremental expansions in growing markets.

For 2005, Williams expects to generate $545 million to $585 million in segment profit from Gas Pipeline.

Power: Keeps Producing Positive Cash Flow

In September 2004, Williams announced its decision to continue operating the Power business and cease efforts to exit the business.

Power is focused on realizing expected cash flows, managing forward commodity risk and providing functions that support Williams' natural gas businesses.

Power, which manages more than 7,700 megawatts of power through long-term contracts, reported 2004 segment profit of $76.7 million. This includes the benefit of $304 million in forward unrealized mark-to-market gains.

A year ago, Power reported segment profit of $135.1 million on a restated basis, which included forward unrealized mark-to-market gains of $262 million, and approximately $208 million in gains on the sale of assets and contracts.

The 2004 decrease in segment profit is due primarily to reduced realized gross margin in power and natural gas, largely reflecting lower sales volumes. Also contributing to the decrease was the absence of gains on the 2003 sale of assets and contracts, partially offset by higher unrealized mark-to-market gains and significantly lower selling, general and administrative costs associated with staff reductions. The absence of certain impairment charges and loss accruals totaling approximately $143 million recorded in 2003 further offset the decline.

For the fourth quarter of 2004, Power reported a segment loss of $44.4 million vs. a segment loss of $101 million for the same period last year on a restated basis. The 2004 period includes forward unrealized mark-to-market gains of $23 million vs. gains of $85 million in 2003.

In 2004, Power generated approximately $565 million in cash flow from operations, largely from reductions in working capital used for credit and collateralization requirements. The unit also benefited from positive cash flows from its power and natural gas commodity portfolios. In 2003, Power generated approximately $162 million in cash flow from operations.

For 2005, Williams expects a segment loss of $150 million to $250 million from Power. The loss is due to the approximate $300 million negative residual effect of having recognized mark-to-market gains on certain Power derivatives contracts in 2003 and 2004. Prior to October 2004, the unit did not qualify for hedge accounting due to Williams' previous intent to exit the business. On a basis adjusted for the residual impact of mark-to-market accounting, Power expects segment profit of $50 million to $150 million.

Power expects cash flow from operations of $50 million to $150 million in 2005.

Other

In the Other segment, the company reported a 2004 segment loss of $41.6 million. A year ago, Other reported a segment loss of $50.5 million.

The segment losses for both 2004 and 2003 are largely the result of impairment charges and equity losses associated with an investment in a Texas pipeline project.

For the fourth quarter of 2004, Other reported a segment loss of $21.0 million vs. a segment loss of $7.7 million for the same period last year.

The increase in quarterly segment loss is primarily due to increased equity losses associated with the Texas pipeline project and an $11.8 million accrual for environmental remediation at the Augusta refinery site.

Guidance Through 2007

In 2005, Williams expects consolidated segment profit of $1.05 billion to $1.35 billion; cash flow provided from operating activities of $1.3 billion to $1.6 billion; and recurring income from continuing operations of 31 cents to 56 cents per share.

On a recurring basis adjusted for the impact of mark-to-market accounting, Williams expects earnings of 63 cents to 88 cents per share for 2005.

In 2006, Williams expects consolidated segment profit of $1.2 billion to $1.5 billion and cash flow provided from operating activities of $1.45 billion to $1.75 billion.

In 2007, Williams expects consolidated segment profit of approximately $1.4 billion to $1.8 billion and cash flow provided from operating activities of $1.6 billion to $1.9 billion.

The company has an overall capital budget of $1.0 billion to $1.2 billion for 2005; $1.15 billion to $1.35 billion for 2006; and $900 million to $1.1 billion in 2007.

Today’s Analyst Call

Williams’ management will discuss the company’s fourth-quarter and year-end 2004 financial results during an analyst presentation to be webcast live at 10 a.m. Eastern today.

Participants are encouraged to access the presentation and corresponding slides via www.williams.com. A limited number of phone lines also will be available at (800) 811-7286. International callers should dial (913) 981-4902. Callers should dial in at least 10 minutes prior to the start time. The webcast replay – audio and slides – for the year-end presentation will be available at www.williams.com later today. Audio-only replays of the presentation will be available at approximately 3 p.m. Eastern today through midnight on March 1. To access the replay, dial (888) 203-1112. International callers should dial (719) 457-0820. The replay confirmation code is 404873.

Form 10-K Filing Schedule

The company plans to file its Form 10-K with the Securities and Exchange Commission in March. The document will be available on both the SEC and Williams' websites. A financial highlights package that is immediately available accompanies this news release.

About Williams (NYSE:WMB)

Williams, through its subsidiaries, primarily finds, produces, gathers, processes and transports natural gas. The company also manages a wholesale power business. Williams' operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard. More information is available at www.williams.com.

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Williams' reports, filings, and other public announcements might contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of Private Securities Litigation Reform Act of 1995. You typically can identify forward-looking statements by the use of forward-looking words, such as "anticipate," believe," "could," "continue," "estimate," "expect," "forecast," "may," "plan," "potential," "project," "schedule," "will," and other similar words. These statements are based on our intentions, beliefs, and assumptions about future events and are subject to risks, uncertainties, and other factors. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, other factors could cause our actual results to differ materially from the results expressed or implied in any forward-looking statements. Those factors include, among others: changes in general economic conditions and changes in the industries in which Williams conducts business; changes in federal or state laws and regulations to which Williams is subject, including tax, environmental and employment laws and regulations; the cost and outcomes of legal and administrative claims proceedings, investigations, or inquiries; the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including our credit ratings and general economic conditions; the level of creditworthiness of counterparties to our transactions; the amount of collateral required to be posted from time to time in our transactions; the effect of changes in accounting policies; the ability to control costs; the ability of each business unit to successfully implement key systems, such as order entry systems and service delivery systems; the impact of future federal and state regulations of business activities, including allowed rates of return, the pace of deregulation in retail natural gas and electricity markets, and the resolution of other regulatory matters; changes in environmental and other laws and regulations to which Williams and its subsidiaries are subject or other external factors over which we have no control; changes in foreign economies, currencies, laws and regulations, and political climates, especially in Canada, Argentina, Brazil, and Venezuela, where Williams has direct investments; the timing and extent of changes in commodity prices, interest rates, and foreign currency exchange rates; the weather and other natural phenomena; the ability of Williams to develop or access expanded markets and product offerings as well as their ability to maintain existing markets; the ability of Williams and its subsidiaries to obtain governmental and regulatory approval of various expansion projects; future utilization of pipeline capacity, which can depend on energy prices, competition from other pipelines and alternative fuels, the general level of natural gas and petroleum product demand, decisions by customers not to renew expiring natural gas transportation contracts; the accuracy of estimated hydrocarbon reserves and seismic data; and global and domestic economic repercussions from terrorist activities and the government's response to such terrorist activities. In light of these risks, uncertainties, and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time that we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Reconciliation of Income (Loss) from Continuing Operations to Recurring Earnings
(UNAUDITED)

(Dollars in millions, except for per-share amounts)	2003 1st Qtr *	2003 2nd Qtr *	2003 3rd Qtr *	2003 4th Qtr *	2003 Year *	2004 1st Qtr *	2004 2nd Qtr*	2004 3rd Qtr*	2004 4th Qtr	2004 Year
Income (loss) from continuing operations[1]	($52.2)	$ 50.0	$ 18.0	($73.3)	($57.5)	$ 0.0	($18.5)	$ 16.2	$ 95.5	$ 93.2
Preferred stock dividends	6.8	22.7	—	—	29.5	—	—	—	—	—
Income (loss) from continuing operations available to common stockholders	($59.0)	$ 27.3	$ 18.0	($73.3)	($87.0)	$ 0.0	($18.5)	$ 16.2	$ 95.5	$ 93.2
Income (loss) from continuing operations — diluted earnings per share	($0.12)	$ 0.05	$ 0.03	($0.14)	($0.17)	$ —	($0.03)	$ 0.03	$ 0.17	$ 0.17
Nonrecurring items:										
Power										
Accelerated compensation expense associated with workforce reductions	11.8	—	—	—	11.8	—	—	—	—	—
Severance accrual	—	0.6	—	—	0.6	—	—	—	—	—
Impairment of investment in Aux Sable	—	8.5	5.6	—	14.1	—	—	—	—	—
Loss accrual for regulatory issues[2]	—	20.0	—	—	20.0	—	—	—	—	—
Prior period item correction[3]	(13.7)	(93.1)	(1.0)	(9.0)	(116.8)	—	—	—	—	—
Gain on sale of Jackson EMC power contracts	—	(175.0)	(13.0)	—	(188.0)	—	—	—	—	—
Gain on sale of crude contracts and pipeline	—	(7.1)	—	—	(7.1)	—	—	—	—	—
Gain on sale of eSpeed stock	—	—	(13.5)	—	(13.5)	—	—	—	—	—
Impairment of goodwill[2]	—	—	—	45.0	45.0	—	—	—	—	—
Hazelton impairment	—	—	—	44.1	44.1	—	—	—	—	—
California rate refund and other accrual adjustments[4]	—	—	—	33.3	33.3	—	—	—	—	—
Total Power nonrecurring items	(1.9)	(246.1)	(21.9)	113.4	(156.5)	—	—	—	—	—
Gas Pipeline										
Write-off of Oneline information system project	—	25.5	—	0.1	25.6	—	—	—	—	—
Severance accrual	—	0.9	—	—	0.9	—	—			—
Write-off of previously-capitalized costs — idled segment of Northwest's pipeline	—	—	—	—	—	—	9.0			9.0
Total Gas Pipeline nonrecurring items	—	26.4	—	0.1	26.5	—	9.0	—	—	9.0
Exploration & Production										
Gain on sale of certain E&P properties	—	(91.5)	—	—	(91.5)	—	—	—	—	—
Loss provision related to an ownership dispute	—	—	—	—	—	—	11.3	—	4.1	15.4
Total Exploration & Production nonrecurring items	—	(91.5)	—	—	(91.5)	—	11.3	—	4.1	15.4
Midstream Gas & Liquids										
La Maquina depreciable life adjustment	—	—	4.2	—	4.2	—	—	6.4	1.2	7.6
Gain on sale of Louisiana Olefins assets	—	—	—	—	—	—	—	—	(9.5)	(9.5)
Gain on sale of West Texas LPG Pipeline, L.P.	—	—	(11.0)	—	(11.0)	—	—	—	—	—
Gain on sale of wholesale propane	—	—	—	(16.2)	(16.2)	—	—	—	—	—
Gulf Liquids arbitration award (Winterthur)	—	—	—	—	—	—	—	—	(93.6)	(93.6)
Impairment of Discovery	—	—	—	—	—	—	—	—	16.9	16.9
Gulf Liquids impairment	—	92.6	(0.3)	16.4	108.7	—	—	—	—	—
Devil's Tower revenue correction	—	—	—	—	—	—	(16.5)	16.5		—
Total Midstream Gas & Liquids nonrecurring items	—	92.6	(7.1)	0.2	85.7	—	(16.5)	22.9	(85.0)	(78.6)
Other										
Impairment of Longhorn and Aspen project[5]	—	49.6	—	—	49.6	—	10.8	—	—	10.8
Gain on sale of butane blending inventory	—	—	(9.2)	—	(9.2)	—	—			—
Augusta environmental reserve	—	—	—	—	—	—	—	—	11.8	11.8
Longhorn recapitalization fee	—	—	—	—	—	6.5	—	—	—	6.5
Total Other nonrecurring items	—	49.6	(9.2)	—	40.4	6.5	10.8	—	11.8	29.1
Nonrecurring items included in segment profit (loss)	(1.9)	(169.0)	(38.2)	113.7	(95.4)	6.5	14.6	22.9	(69.1)	(25.1)
Nonrecurring items below segment profit (loss)										
Convertible preferred stock dividends[2] (Preferred stock dividends — Corporate)	—	13.8	—	—	13.8	—	—	—	—	—
Impairment of cost-based investments[6] (Investing income (loss)-Various)	—	19.1	2.3	—	21.4	—	—	15.7	2.3	18.0
Severance accrual (General corporate expenses)	—	3.0	—	—	3.0	—	—	—	—	—
Impairment of Algar Telecom investment (Investing income (loss) — Other)	12.0	—	1.2	—	13.2	—	—	—	—	—
Write-off of capitalized debt expense (Interest accrued — Corporate)	—	14.5	—	—	14.5	—	3.8	—	—	3.8
Premiums, fees and expenses related to the debt repurchase and debt tender offer (Other income (expense) — net — Corporate and Exploration & Production)	—	—	—	66.8	66.8	—	96.7	155.1	29.7	281.5
Gulf Liquids arbitration award (Winterthur) — interest income — (Investing income loss) — Midstream)	—	—	—	—	—	—	—	—	(9.6)	(9.6)
Loss provision related to an ownership dispute — interest component (Interest accrued — Exploration & Production)	—	—	—	—	—	—	1.9	—	2.1	4.0
	12.0	50.4	3.5	66.8	132.7	—	102.4	170.8	24.5	297.7
Total nonrecurring items	10.1	(118.6)	(34.7)	180.5	37.3	6.5	117.0	193.7	(44.6)	272.6
Tax effect for above items	3.9	(73.3)	(14.2)	49.7	(33.9)	2.5	44.8	74.1	(17.1)	104.3
Recurring income (loss) from continuing operations available to common stockholders	($52.8)	($18.0)	($2.5)	$ 57.5	($15.8)	$ 4.0	$ 53.7	$ 135.8	$ 68.0	$ 261.5
Recurring diluted earnings per common share	($0.10)	($0.03)	$ —	$ 0.11	($0.03)	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.49
Weighted-average shares — diluted (thousands)	517,652	524,546	524,711	518,502	518,137	519,485	521,698	529,525	586,497	535,611

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(1) **Includes $126.8 million positive valuation adjustment associated with agreement to terminate contract with Allegheny in second quarter 2003.**

(2) **No tax benefit.**

(3) **Power recognized $116.8 million of revenue in 2003 from a correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001.**

(4) **For $5.6 million, no tax benefit.**

(5) **For $20.2 million, no tax benefit in 2nd Qtr 2003.**

(6) **For $21.4 million in 2003, no tax benefit.**

* Amounts have been restated from 3rd Quarter 2004 to reflect Gulf Liquids as continuing operations.

Note: The sum of earnings (loss) per share for the quarters may not equal the total earnings (loss) per share for the year due to changes in the weighted-average number of common shares outstanding.

Adjustment to remove MTM impact

Dollars in millions except for per share amounts	2004					2003				
	1Q	**2Q**	**3Q**	**4Q**	**Year**	**1Q**	**2Q**	**3Q**	**4Q**	**Year**
Recurring income from cont. ops available to common shareholders	**$ 4**	**$ 54**	**$ 136**	**$ 68**	**$ 261**	**$ (53)**	**$ (18)**	**$ (2)**	**$ 58**	**$ (16)**
Recurring diluted earnings per common share	**$ 0.01**	**$ 0.10**	**$ 0.26**	**$ 0.12**	**$ 0.49**	**$ (0.10)**	**$ (0.03)**	**$ (0.00)**	**$ 0.11**	**$ (0.03)**
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(24)	(70)	(188)	(23)	(304)	1	(232)	54	(85)	(262)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186	(17)	45	(45)	25	8
Total MTM adjustments	112	(59)	(143)	(29)	(118)	(15)	(187)	9	(60)	(253)
Tax effect of total MTM adjustments (at 39%)	44	(23)	(56)	(11)	(46)	(6)	(73)	4	(23)	(99)
After tax MTM adjustments	69	(36)	(87)	(17)	(72)	(9)	(114)	5	(37)	(155)
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 73**	**$ 18**	**$ 49**	**$ 51**	**$ 190**	**$ (62)**	**$ (132)**	**$ 3**	**$ 22**	**$ (170)**
Recurring diluted earnings per share after MTM adj.	**$ 0.14**	**$ 0.03**	**$ 0.09**	**$ 0.09**	**$ 0.35**	**$ (0.12)**	**$ (0.25)**	**$ 0.01**	**$ 0.04**	**$ (0.33)**
weighted average shares — diluted (thousands)	519,485	521,698	529,525	586,497	535,611	517,652	524,546	524,711	518,502	518,137

Note: Recurring income from continuing operations available to common stockholders has been restated to reflect the reclassification of Gulf Liquids to continuing operations

Adjustments have been made to reverse estimated forward unrealized MTM gains/losses and add estimated realized gains/losses from MTM previously recognized, i.e. assumes MTM accounting had never been applied to designated hedges and other derivatives.

Non-GAAP Utility Statement:

This press release includes certain financial measures, EBITDA, free cash flow, recurring earnings and recurring segment profit, that are non-GAAP financial measures as defined under the rules of the Securities and Exchange Commission. EBITDA represents the sum of net income (loss), net interest expense, income taxes, depreciation and amortization of intangible assets, less income (loss) from discontinued operations. Recurring earnings and recurring segment profit provide investors meaningful insight into the Company's results from ongoing operations. This press release is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Management uses these financial measures because they are widely accepted financial indicators used by investors to compare company performance. In addition, management believes that these measures provide investors an enhanced perspective of the operating performance of the Company's assets and the cash that the business is generating. Neither EBITDA nor recurring earnings, free cash flow and recurring segment profit are intended to represent cash flows for the period, nor are they presented as an alternative to net income or cash flow from operations. They should not be considered in isolation or as substitutes for a measure of performance prepared in accordance with United States generally accepted accounting principles.

Certain financial information in this press release is also shown including Power mark-to-market adjustments. This press release is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Previously the Company did not qualify for hedge accounting with respect to its Power segment as a result of the Company's stated intent to exit the Power business. The Company ceased efforts to market the sale of Power during the third quarter 2004, and now qualifies for hedge accounting. Hedge accounting reduces earnings volatility associated with Power's portfolio of certain derivative hedging instruments. Prior to the adoption of hedge accounting, these derivative hedging instruments were accounted for on a mark-to-market basis with the change in fair value recognized in earnings each period. Management uses the mark-to-market adjustments to better reflect Power's results on a basis that is more consistent with Power's portfolio cash flows and to aid investor understanding. The adjustments reverse forward unrealized mark-to-market gains or losses from derivatives and add realized gains or losses from derivatives for which mark-to-market income has been previously recognized, with the effect that the resulting adjusted segment profit is presented as if mark-to-market accounting had never been applied to designated hedges or other derivatives. The measure is limited by the fact that it does not reflect potential unrealized future losses or gains on derivative contracts. However, management compensates for this limitation since reported earnings do reflect unrealized gains and losses of derivative contracts. Overall, management believes the mark-to-market adjustments provide an alternative measure that more closely matches realized cash flows for the Power segment.

Financial Highlights

(Unaudited)

(Millions, except per-share amounts)	Three months ended December 31, 2004		Three months ended December 31, 2003*		Years ended December 31, 2004		Years ended December 31, 2003*
Revenues	**$**	**2,964.2**	$	3,513.5	**$**	**12,461.3**	$	16,651.0
Income (loss) from continuing operations	**$**	**95.5**	$	(73.3)	**$**	**93.2**	$	(57.5)
Income (loss) from discontinued operations	**$**	**(22.1)**	$	19.6	**$**	**70.5**	$	326.6
Cumulative effect of change in accounting principles	**$**	**—**	$	—	**$**	**—**	$	(761.3)
Net income (loss)	**$**	**73.4**	$	(53.7)	**$**	**163.7**	$	(492.2)
Basic earnings (loss) per common share:								
Income (loss) from continuing operations	**$**	**.17**	$	(.14)	**$**	**.18**	$	(.17)
Income (loss) from discontinued operations	**$**	**(.04)**	$	.04	**$**	**.13**	$	.63
Cumulative effect of change in accounting principles	**$**	**—**	$	—	**$**	**—**	$	(1.47)
Net income (loss)	**$**	**.13**	$	(.10)	**$**	**.31**	$	(1.01)
Average shares (thousands)		**552,272**		518,502		**529,188**		518,137
Diluted earnings (loss) per common share:								
Income (loss) from continuing operations	**$**	**.17**	$	(.14)	**$**	**.18**	$	(.17)
Income (loss) from discontinued operations	**$**	**(.04)**	$	.04	**$**	**.13**	$	.63
Cumulative effect of change in accounting principles	**$**	**—**	$	—	**$**	**—**	$	(1.47)
Net income (loss)	**$**	**.13**	$	(.10)	**$**	**.31**	$	(1.01)
Average shares (thousands)		**586,497**		518,502		**535,611**		518,137
Shares outstanding at December 31 (thousands)						**557,957**		518,232

*Amounts have been restated or reclassified as described in Note 1 of Notes to Consolidated Statement of Operations.

Consolidated Statement of Operations

(UNAUDITED)

(Millions, except per-share amounts)	Three months ended December 31, 2004	Three months ended December 31, 2003*	Years ended December 31, 2004	Years ended December 31, 2003*
REVENUES				
Power	**$ 2,038.6**	$ 2,585.4	**$ 9,272.4**	$ 13,195.5
Gas Pipeline	**351.3**	364.0	**1,362.3**	1,368.3
Exploration & Production	**214.1**	166.9	**777.6**	779.7
Midstream Gas & Liquids	**867.1**	709.7	**2,882.6**	2,784.8
Other	**6.5**	12.9	**32.8**	72.0
Intercompany eliminations	**(513.4)**	(325.4)	**(1,866.4)**	(1,549.3)
Total revenues	**2,964.2**	3,513.5	**12,461.3**	16,651.0
SEGMENT COSTS AND EXPENSES				
Costs and operating expenses	**2,543.5**	3,152.8	**10,751.7**	15,004.3
Selling, general and administrative expenses	**97.8**	92.7	**355.5**	421.3
Other (income) expense – net	**(77.4)**	135.6	**(51.6)**	(21.3)
Total segment costs and expenses	**2,563.9**	3,381.1	**11,055.6**	15,404.3
General corporate expenses	**35.3**	24.5	**119.8**	87.0
OPERATING INCOME				
Power	**(50.8)**	(110.6)	**86.5**	145.3
Gas Pipeline	**148.0**	142.2	**557.6**	539.6
Exploration & Production	**67.7**	48.3	**223.9**	392.5
Midstream Gas & Liquids	**247.0**	58.5	**552.2**	178.0
Other	**(11.6)**	(6.0)	**(14.5)**	(8.7)
General corporate expenses	**(35.3)**	(24.5)	**(119.8)**	(87.0)
Total operating income	**365.0**	107.9	**1,285.9**	1,159.7
Interest accrued	**(171.5)**	(251.1)	**(834.4)**	(1,293.5)
Interest capitalized	**1.0**	10.9	**6.7**	45.5
Interest rate swap income (loss)	**.3**	4.2	**(5.0)**	(2.2)
Investing income	**16.8**	29.5	**48.0**	73.2
Early debt retirement costs	**(29.7)**	(66.8)	**(282.1)**	(66.8)
Minority interest in income and preferred returns of consolidated subsidiaries	**(5.4)**	(4.3)	**(21.4)**	(19.4)
Other income – net	**7.2**	1.0	**26.8**	40.7
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	**183.7**	(168.7)	**224.5**	(62.8)
Provision (benefit) for income taxes	**88.2**	(95.4)	**131.3**	(5.3)
Income (loss) from continuing operations	**95.5**	(73.3)	**93.2**	(57.5)
Income (loss) from discontinued operations	**(22.1)**	19.6	**70.5**	326.6
Income (loss) before cumulative effect of change in accounting principles	**73.4**	(53.7)	**163.7**	269.1
Cumulative effect of change in accounting principles	**—**	—	**—**	(761.3)
Net income (loss)	**73.4**	(53.7)	**163.7**	(492.2)
Preferred stock dividends	**—**	—	**—**	29.5
Income (loss) applicable to common stock	**$ 73.4**	$ (53.7)	**$ 163.7**	$ (521.7)
EARNINGS (LOSS) PER SHARE				
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	**$ .17**	$ (.14)	**$ .18**	$ (.17)
Income (loss) from discontinued operations	**(.04)**	.04	**.13**	.63
Income (loss) before cumulative effect of change in accounting principles	**.13**	(.10)	**.31**	.46
Cumulative effect of change in accounting principles	**—**	—	**—**	(1.47)
Net income (loss)	**$ .13**	$ (.10)	**$ .31**	$ (1.01)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	**$ .17**	$ (.14)	**$ .18**	$ (.17)
Income (loss) from discontinued operations	**(.04)**	.04	**.13**	.63
Income (loss) before cumulative effect of change in accounting principles	**.13**	(.10)	**.31**	.46
Cumulative effect of change in accounting principles	**—**	—	**—**	(1.47)
Net income (loss)	**$ .13**	$ (.10)	**$ .31**	$ (1.01)

*Certain amounts have been restated or reclassified as described in Note 1 of Notes to Consolidated Statement of Operations.

See accompanying notes.

1. Basis of presentation

Discontinued operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the results of operations for the following components have been reflected in the Consolidated Statement of Operations as discontinued operations (see Note 7):

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream Gas & Liquids (Midstream) segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and
- straddle plants in western Canada, previously part of the Midstream segment.

During fourth-quarter 2004, we reclassified the operations of Gulf Liquids New River Project LLC (Gulf Liquids) to continuing operations within our Midstream segment in accordance with Emerging Issues Task Force (EITF) Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations" (EITF 03-13), which was issued in the fourth quarter. Under the provisions of EITF 03-13, Gulf Liquids activities no longer qualify for reporting as discontinued operations based on management's expectation that we will continue to have significant commercial activity with the disposed entity. The operations of Gulf Liquids were reclassified to continuing operations within our Midstream segment. All periods presented reflect these reclassifications.

Unless indicated otherwise, the information in the Notes to the Consolidated Statement of Operations relates to our continuing operations. Other components of our business may be classified as discontinued operations in the future as those operations are sold or classified as held-for-sale.

2. Hedge accounting – power segment

As a result of our past intent to exit the Power business, our Power segment did not previously qualify for hedge accounting. Therefore, we reported changes in the forward fair value of our derivative contracts in earnings as unrealized gains or losses. However, with the decision to retain the business, Power became eligible for hedge accounting under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," and elected hedge accounting beginning October 1, 2004, on a prospective basis for certain qualifying derivative contracts. Under cash flow hedge accounting, to the extent that the hedges are effective, prospective changes in the forward fair value of the hedges are reported as changes in other comprehensive income in the equity section of the balance sheet, and then reclassified to earnings when the underlying hedged transactions (i.e. power sales and gas purchases) affect earnings.

3. Segment revenues and profit (loss)

Segments – performance measurement

We currently evaluate performance based on segment profit (loss) from operations, which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on impairments related to investments accounted for under the equity method. Equity earnings (losses) and income (loss) from investments are reported in investing income in the Consolidated Statement of Operations.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties. External Revenues of our Exploration & Production segment includes third party oil and gas sales, more than offset by transportation expenses and royalties due third parties on intercompany sales.

3. SEGMENT REVENUES AND PROFIT (LOSS) (continued)

Reclassification of operations

Due in part to FERC Order 2004, management and decision-making control of certain activities were transferred from our Midstream segment. Certain regulated gas gathering assets were transferred from our Midstream segment to our Gas Pipeline segment effective June 1, 2004, and our equity method investment in the Aux Sable gas processing plant and related business was transferred from our Midstream segment to our Power segment effective September 21, 2004. Consequently, the results of operations were similarly reclassified. All periods presented reflect these classifications.

(Unaudited)

3. Segment revenues and profit (loss) (continued)

(Millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Three months ended December 31, 2004							
Segment revenues:							
External	**$ 1,784.8**	**$ 345.7**	**$ (27.7)**	**$ 859.2**	**$ 2.2**	**$ —**	**$ 2,964.2**
Internal	**256.7**	**5.6**	**241.8**	**7.9**	**4.3**	**(516.3)**	**—**
Total segment revenues	**2,041.5**	**351.3**	**214.1**	**867.1**	**6.5**	**(516.3)**	**2,964.2**
Less intercompany interest rate swap income	**2.9**	**—**	**—**	**—**	**—**	**(2.9)**	**—**
Total revenues	**$ 2,038.6**	**$ 351.3**	**$ 214.1**	**$ 867.1**	**$ 6.5**	**$ (513.4)**	**$ 2,964.2**
Segment profit (loss)	**$ (44.4)**	**$ 156.8**	**$ 70.9**	**$ 235.7**	**$ (21.0)**	**$ —**	**$ 398.0**
Less:							
Equity earnings (losses)	**3.5**	**8.8**	**3.2**	**5.5**	**(9.3)**	**—**	**11.7**
Income (loss) from investments	**—**	**—**	**—**	**(16.8)**	**(.1)**	**—**	**(16.9)**
Intercompany interest rate swap income	**2.9**	**—**	**—**	**—**	**—**	**—**	**2.9**
Segment operating income (loss)	**$ (50.8)**	**$ 148.0**	**$ 67.7**	**$ 247.0**	**$ (11.6)**	**$ —**	**400.3**
General corporate expenses							**(35.3)**
Consolidated operating income							**$ 365.0**
Three months ended December 31, 2003							
Segment revenues:							
External	$ 2,455.5	$ 361.6	$ (8.8)	$ 702.1	$ 3.1	$ —	$ 3,513.5
Internal	139.6	2.4	175.7	7.6	9.8	(335.1)	—
Total segment revenues	2,595.1	364.0	166.9	709.7	12.9	(335.1)	3,513.5
Less intercompany interest rate swap income	9.7	—	—	—	—	(9.7)	—
Total revenues	$ 2,585.4	$ 364.0	$ 166.9	$ 709.7	$ 12.9	$ (325.4)	$ 3,513.5
Segment profit (loss)	$ (101.0)	$ 148.2	$ 50.1	$ 63.8	$ (7.7)	$ —	$ 153.4
Less:							
Equity earnings (losses)	.4	6.0	1.8	1.0	(1.1)	—	8.1
Income (loss) from investments	(.5)	—	—	4.3	(.6)	—	3.2
Intercompany interest rate swap income	9.7	—	—	—	—	—	9.7
Segment operating income (loss)	$ (110.6)	$ 142.2	$ 48.3	$ 58.5	$ (6.0)	$ —	132.4
General corporate expenses							(24.5)
Consolidated operating income							$ 107.9

3. Segment revenues and profit (loss) (continued)

(Millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Year ended December 31, 2004							
Segment revenues:							
External	**$ 8,346.2**	**$ 1,345.0**	**$ (84.0)**	**$ 2,844.7**	**$ 9.4**	**$ —**	**$ 12,461.3**
Internal	**912.5**	**17.3**	**861.6**	**37.9**	**23.4**	**(1,852.7)**	**—**
Total segment revenues	**9,258.7**	**1,362.3**	**777.6**	**2,882.6**	**32.8**	**(1,852.7)**	**12,461.3**
Less intercompany interest rate swap loss	**(13.7)**	**—**	**—**	**—**	**—**	**13.7**	**—**
Total revenues	**$ 9,272.4**	**$ 1,362.3**	**$ 777.6**	**$ 2,882.6**	**$ 32.8**	**$ (1,866.4)**	**$ 12,461.3**
Segment profit (loss)	**$ 76.7**	**$ 585.8**	**$ 235.8**	**$ 549.7**	**$ (41.6)**	**$ —**	**$ 1,406.4**
Less:							
Equity earnings (losses)	**3.9**	**29.2**	**11.9**	**14.6**	**(9.7)**	**—**	**49.9**
Loss from investments	**—**	**(1.0)**	**—**	**(17.1)**	**(17.4)**	**—**	**(35.5)**
Intercompany interest rate swap loss	**(13.7)**	**—**	**—**	**—**	**—**	**—**	**(13.7)**
Segment operating income (loss)	**$ 86.5**	**$ 557.6**	**$ 223.9**	**$ 552.2**	**$ (14.5)**	**$ —**	**1,405.7**
General corporate expenses							**(119.8)**
Consolidated operating income							**$ 1,285.9**
Year ended December 31, 2003							
Segment revenues:							
External	$ 12,570.5	$ 1,344.3	$ (36.3)	$ 2,740.2	$ 32.3	$ —	$ 16,651.0
Internal	622.1	24.0	816.0	44.6	39.7	(1,546.4)	—
Total segment revenues	13,192.6	1,368.3	779.7	2,784.8	72.0	(1,546.4)	16,651.0
Less intercompany interest rate swap loss	(2.9)	—	—	—	—	2.9	—
Total revenues	$ 13,195.5	$ 1,368.3	$ 779.7	$ 2,784.8	$ 72.0	$ (1,549.3)	$ 16,651.0
Segment profit (loss)	$ 135.1	$ 555.5	$ 401.4	$ 197.3	$ (50.5)	$ —	$ 1,238.8
Less:							
Equity earnings (losses)	(4.9)	15.8	8.9	(.8)	1.3	—	20.3
Income (loss) from investments	(2.4)	.1	—	20.1	(43.1)	—	(25.3)
Intercompany interest rate swap loss	(2.9)	—	—	—	—	—	(2.9)
Segment operating income (loss)	$ 145.3	$ 539.6	$ 392.5	$ 178.0	$ (8.7)	$ —	1,246.7
General corporate expenses							(87.0)
Consolidated operating income							$ 1,159.7

4. Asset sales, impairments and other accruals

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense – net within segment costs and expenses for the three months and the years ended December 31, 2004 and 2003, are as follows:

	(Income) Expense			
	Three months ended December 31,		Years ended December 31,	
(millions)	**2004**	2003	**2004**	2003
Power				
Gain on sale of Jackson power contract	**$ —**	$ —	**$ —**	$ (188.0)
Impairment of goodwill	**—**	45.0	**—**	45.0
Impairment of generation facilities	**—**	44.1	**—**	44.1
Commodity Futures Trading Commission settlement	**—**	—	**—**	20.0
California rate refund and other accrual adjustments	**—**	19.5	**—**	19.5
Gas Pipeline				
Write-off of previously-capitalized costs on an idled segment of a pipeline	**—**	—	**9.0**	—
Write-off of software development costs due to cancelled implementation	**—**	.1	**—**	25.6
Exploration & Production				
Loss provision related to an ownership dispute	**4.1**	—	**15.4**	—
Net gain on sale of certain natural gas properties	**—**	(.3)	**—**	(96.7)
Midstream Gas & Liquids				
Gain on sale of the wholesale propane business	**—**	(16.2)	**—**	(16.2)
Impairment of Gulf Liquids assets	**2.5**	16.4	**2.5**	108.7
Arbitration award on a Gulf Liquids insurance claim dispute	**(93.6)**	—	**(93.6)**	—
Other				
Gain on sale of blending assets	**—**	—	**—**	(9.2)
Environmental accrual related to the Augusta refinery facility	**11.8**	—	**11.8**	—

Power

Goodwill. During 2003, we were pursuing a strategy of exiting the Power business. Because of this and the market conditions in which this business operated, we evaluated Power's remaining goodwill for impairment. In estimating the fair value of the Power segment, we considered our derivative portfolio which is carried at fair value on the balance sheet, and our non-derivative portfolio, which is no longer carried at fair value on the balance sheet. Because of the significant negative fair value of certain of our non-derivative contracts, we may be unable to realize our carrying value of this reporting unit. As a result, we recognized a $45 million impairment of the remaining goodwill within Power during 2003.

Generation facilities. The 2003 impairment relates to the Hazelton generation facility. Fair value was estimated using future cash flows based on current market information and discounted at a risk adjusted rate.

California rate refund and other accrual adjustments. In addition to the $19.5 million charge included in other (income) expense – net within segment costs and expenses for 2003, a $13.8 million charge is recorded within costs and operating expenses. These two amounts, totaling $33.3 million, are for California rate refund and other accrual adjustments and relate to power marketing activities in California during 2000 and 2001.

Midstream Gas & Liquids

Impairment of Gulf Liquids assets. During second-quarter 2003, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the assets of Gulf Liquids. We are currently negotiating purchase and sale agreements related to the sale of these assets. We expect the sale of these operations to close by March 31, 2005. We recognized impairment charges of $2.5 million in the fourth quarter of 2004 and $108.7 million during 2003 to reduce the carrying cost of the long-lived assets to estimated fair value less costs to sell the assets. We estimated fair value based on a probability-weighted analysis of various scenarios including expected sales prices, discounted cash flows and salvage valuations. Prior to fourth-quarter 2004, the operations of Gulf Liquids were included in discontinued operations.

Arbitration award on a Gulf Liquids insurance claim dispute. Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, plus interest of $9.6 million. Following the arbitration decision, Winterthur filed a Petition to Vacate the Final Award in the New York State court and Gulf Liquids filed a Cross-Petition to Confirm the Final Award. Prior to the State court's ruling, Winterthur agreed to the terms of the award and on November 1, 2004, remitted the proceeds to us. As a result, we recognized total income of approximately $103 million related to the arbitration award in fourth-quarter 2004.

4. Asset sales, impairments and other accruals (continued)

Other

Environmental accrual related to the Augusta refinery facility. As a result of new information obtained in the fourth quarter related to the Augusta refinery site, we have accrued additional amounts for completion of work under a current Administrative Order on Consent and reasonably estimated net remediation costs. Accruals may be adjusted as more information from the site investigation becomes available.

5. Investing income

Investing income for the three months and the years ended December 31, 2004 and 2003, is as follows:

	Three months ended December 31,		Years ended December 31,	
(millions)	**2004**	2003	**2004**	2003
Equity earnings*	**$ 11.7**	$ 8.1	**$ 49.9**	$ 20.3
Income (loss) from investments*	**(16.9)**	3.2	**(35.5)**	(25.3)
Impairments of cost-based investments	**(5.1)**	(.4)	**(28.5)**	(35.0)
Interest income and other	**27.1**	18.6	**62.1**	113.2
Total	**$ 16.8**	$ 29.5	**$ 48.0**	$ 73.2

*Item also included in segment profit (see Note 3).

Income (loss) from investments for the year ended December 31, 2004, includes:

- a $10.8 million additional impairment of our investment in equity securities of Longhorn Partners, Pipeline L.P. (Longhorn) primarily associated with the terms of a recapitalization plan, which is included in our Other segment;
- $6.5 million net unreimbursed Longhorn recapitalization advisory fees, which is included in our Other segment; and
- a $16.9 million impairment of our equity investment in Discovery Pipeline resulting from management's estimate of fair value, which is included in our Midstream segment.

Income (loss) from investments for the year ended December 31, 2003, includes:

- a $43.1 million impairment of our investment in equity and debt securities of Longhorn, which is included in our Other segment;
- a $14.1 million impairment of our equity interest in Aux Sable, which is included in our Power segment;
- a $13.5 million gain on the sale of stock in eSpeed Inc., which is included in our Power segment; and
- an $11.1 million gain on sale of our equity interest in West Texas LPG Pipeline, L.P. which is included in our Midstream segment.

Impairments of cost-based investments for the years ended December 31, 2004 and 2003, primarily include impairments of certain international investments.

6. Early debt retirement

Early debt retirement costs include payments in excess of the carrying value of the debt, dealer fees and the write-off of deferred debt issuance costs and discount/premium on the debt.

7. Discontinued operations

Summarized results of discontinued operations

The following table presents the summarized results of discontinued operations for the three months and the years ended December 31, 2004 and 2003. Income (loss) from discontinued operations before income taxes for the years ended December 31, 2004 and 2003 includes charges of $152.7 million and $52.7 million, respectively, to increase our accrued liability associated with litigation concerning the Trans-Alaska Pipeline System Quality Bank. 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.

	Three months ended December 31,		Years ended December 31,	
(millions)	**2004**	2003	**2004**	2003
Revenues	**$ —**	$ 289.3	**$ 353.4**	$2,614.6
Income (loss) from discontinued operations before income taxes	**$ (.9)**	$ 32.5	**$(121.3)**	197.5
(Impairments) and gain (loss) on sales — net	**.6**	(2.5)	**200.5**	277.7
Provision for income taxes	**(21.8)**	(10.4)	**(8.7)**	(148.6)
Total income (loss) from discontinued operations	**$ (22.1)**	$ 19.6	**$ 70.5**	$ 326.6

2004 Completed transactions

Canadian straddle plants

On July 28, 2004, we completed the sale of the Canadian straddle plants for approximately $544 million in U.S. funds, including amounts paid to our subsidiaries for amounts previously due from the straddle plants. During third-quarter

7. DISCONTINUED OPERATIONS (continued)

2004, we recognized a pre-tax gain on the sale of $189.8 million, which is included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These assets were previously written down to estimated fair value, resulting in a $36.8 million impairment in 2002 and an additional $41.7 million impairment in 2003. 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 and related assets for approximately $304 million, subject to closing adjustments for items such as the value of petroleum inventories. We received $279 million in cash at the time of sale and $25 million in cash during the second quarter of 2004. Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. As a result, impairment charges of $8 million and $18.4 million were recorded in 2003 and 2002, respectively. We recognized a $3.6 million pre-tax gain on the sale during first-quarter 2004. The gain and the 2003 impairment charge are included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

2003 Completed transactions

Canadian liquids operations

During the third quarter of 2003, we completed the sales of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. We recognized pre-tax gains totaling $92.1 million in 2003 on the sales which are included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These operations were part of the Midstream segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. The December 31, 2002 carrying value resulted from the recognition of impairments of $133.5 million and $170 million in 2002 and 2001, respectively, and reflected the then estimated fair value less cost to sell. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, we recognized additional impairment charges of $17.4 million in 2003. We also recognized a pre-tax loss on the sale in 2003 of $4.2 million. The 2003 impairments and the loss on sale are included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event. We recognized a total pre-tax gain of $310.8 million on the sale during 2003, including the $20 million of additional proceeds, all of which is included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. We deferred an additional $113 million associated with certain indemnifications we provided to the purchasers under the sales agreement. In second-quarter 2004, we settled these indemnifications with an agreement to pay $117.5 million over a four-year period. Williams Energy Partners was a previously reported segment.

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for approximately $59 million in cash. During 2003, we recognized a pre-tax loss on the sale of $5.4 million, which is included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These assets were previously written down by $195.7 million, including $23 million related to goodwill, to their estimated fair value less cost to sell at December 31, 2002. These operations were part of the previously reported Petroleum Services segment.

7. Discontinued operations (continued)

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. We recognized a $39.7 million pre-tax gain on the sale during 2003. The gain is included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. We recorded a $109 million impairment charge in 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on our assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. No significant gain or loss was recognized on the subsequent sale. Texas Gas was a segment within Gas Pipeline.

Midsouth refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee, for $455 million in cash. These assets were previously written down by $240.8 million to their estimated fair value less cost to sell at December 31, 2002. We recognized a pre-tax gain on sale of $4.7 million in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million gain on the sale of an earn-out agreement we retained in the sale of the refinery. These gains are included in (Impairments) and gain (loss) on sales – net in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We had previously written these assets down by $146.6 million in 2002 and $14.7 million in 2001 to their then estimated fair value to sell at December 31, 2002, and did not recognize a significant gain or loss on the sale. These operations were part of the previously reported Petroleum Services segment.

8. Cumulative effect of change in accounting principles

On October 25, 2002, the EITF reached a consensus on Issue No. 02-3, “Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” This Issue rescinded EITF Issue No. 98-10, “Accounting for Contracts Involved in Energy Trading and Risk Management Activities,” the impact of which is to preclude fair value accounting for energy trading contracts that are not derivatives pursuant to SFAS No. 133 and commodity trading inventories. The EITF also reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The consensus is applicable for fiscal periods beginning after December 15, 2002, except for physical trading commodity inventories purchased after October 25, 2002, which may not be reported at fair value. We initially applied the consensus effective January 1, 2003, and reported the initial application as a cumulative effect of a change in accounting principle. The effect of initially applying the consensus reduced net income by approximately $762.5 million on an after tax basis. Physical trading commodity inventories at December 31, 2003, that were purchased prior to October 25, 2002, were reported at fair value at December 31, 2003, and included in the effect of initially applying the consensus. The change results primarily from power tolling load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value. These contracts are now accounted for under an accrual model. Physical trading commodity inventories are stated at cost, not to be in excess of market.

9. Recent accounting standards

In December 2004, the Financial Accounting Standards Board issued revised SFAS No. 123, “Share-Based Payment.” The statement requires that compensation cost for all share based awards to employees be recognized in the financial statements at fair value. The Statement is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. We currently intend to adopt the new statement as of the interim reporting period beginning July 1, 2005. Prior to adoption, we will continue to account for our stock-based compensation plans under Accounting Principles Board Opinion No. 25 and related guidance while applying the proforma disclosure requirements of SFAS No. 148, “Accounting for Stock-Based Compensation—Transition and Disclosure—an amendment of SFAS No. 123.”

EXHIBIT 99.2

Williams 2004 4th Quarter Earnings Release

February 23, 2005

Forward Looking Statements

Our reports, filings, and other public announcements might contain or incorporate by reference statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. You typically can identify forward-looking statements by the use of forward-looking words, such as "anticipate," "believe," "could," "continue," "estimate," "expect," "forecast," "may," "plan," "potential," "project," "schedule," "will," and other similar words. These statements are based on our intentions, beliefs, and assumptions about future events and are subject to risks, uncertainties, and other factors. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, other factors could cause our actual results to differ materially from the results expressed or implied in any forward-looking statements. Those factors include, among others:

- Our businesses are subject to complex government regulations that are subject to changes in the regulations themselves or in their interpretation or implementation;
- Our ability to gain adequate, reliable and affordable access to transmission and distribution assets due to the FERC and regional regulation of wholesale market transactions for electricity and gas;
- Our gas sales, transmission and storage operations are subject to government regulations and rate proceedings that could have an adverse impact on our ability to recover the costs of operating our pipeline facilities;
- The different regional power markets in which we compete or will compete in the future have changing regulatory structures;
- Our risk measurement and hedging activities might not prevent losses;
- Electricity, natural gas liquids and gas prices are volatile and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain existing businesses;
- We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets;
- Our operating results might fluctuate on a seasonal and quarterly basis;
- Risks related to laws of other countries, taxes, economic conditions, fluctuations in currency rates, political conditions and policies of foreign governments;
- Legal proceedings and governmental investigations related to our business;
- Recent developments affecting the wholesale power and energy trading industry sector that have reduced market activity and liquidity;
- Because we no longer maintain investment grade credit ratings, our counterparties have required us to provide higher amounts of credit support;
- Despite our restructuring efforts, we may not attain investment grade ratings;
- Institutional knowledge represented by our former employees now employed by our outsourcing service provider might not be adequately preserved;
- Failure of the outsourcing relationship might negatively impact our ability to conduct our business;
- Our ability to receive services from outsourcing provider locations outside the United States might be impacted by cultural differences, political instability, or unanticipated regulatory requirements in jurisdictions outside the United States;
- We could be held liable for the environmental condition of any of our assets, which could include losses or costs of compliance that exceed our current expectations;
- Environmental regulation and liability relating to our business will be subject to environmental legislation in all jurisdictions in which it operates, and such legislation may be subject to change;
- Potential changes in accounting standards that might cause us to revise our financial disclosure in the future, which might change the way analysts measure our business or financial performance;
- The continued availability of natural gas reserves to our natural gas transmission and midstream businesses;
- Our drilling, production, gathering, processing and transporting activities involve numerous risks that might result in accidents and other operating risks and costs;
- Compliance with the Pipeline Improvement Act may result in unanticipated costs and consequences;
- Estimating reserves and future net revenues involves uncertainties and negative revisions to reserve estimates and oil and gas price declines may lead to impairment of oil and gas assets;
- The threat of terrorist activities and the potential for continued military and other actions;
- The historic drilling success rate of our exploration and production business is no guarantee of future performance; and
- Our assets and operations can be affected by weather and other phenomena.

In light of these risks, uncertainties, and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Oil & Gas Reserves Disclaimer

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We use certain terms in this presentation, such as "probable and possible" reserves that the SEC's guidelines strictly prohibit us from including in filings with the SEC.

The SEC defines proved reserves as estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under the assumed economic conditions. Probable and possible reserves are estimates of potential reserves that are made using accepted geological and engineering analytical techniques, but which are estimated with a reduced level of certainty than for proved reserves. Possible reserve estimates are less certain than those for probable reserves.

Investors are urged to closely consider the disclosures and risk factors in our Forms 10-K and 10-Q, available from our offices or from our website at www.williams.com.

Overview

Steve Malcolm, Chairman, President & CEO

Williams

Overview

What You'll Hear

- Williams delivers strong 4Q performance
  - Midstream sees record quarter due to continued strong margins and record volumes
  - Exploration & Production production volume growth continues
  - Gas Pipeline enjoys best quarter in last two years
  - Power continues positive cash flows
  - Strong consolidated cash flows continue

Overview

What You'll Hear

- Restructuring complete
  - Debt now at $7.8B
  - Debt to capitalization ratio of 61.6%
  - Cash of $1.3B at February 19
- Status of litigation and investigations
  - Significant matters resolved in 2004
    - California utilities' refund claims against Williams
    - Gulf Liquids' insurance arbitration award
  - Significant matters that remain open
    - Securities/ERISA litigation
    - DOJ investigation related to gas price reporting
    - FERC's investigation related to gas storage information

Williams

Overview

What You'll Hear

- E&P growing
  - Production up 25% for the year
  - 248% reserves replacement rate with >99% success rate
  - Total proved reserves 3.2 Tcfe
- Midstream phenomenal
  - Record earnings and NGL production levels
  - Deepwater projects performing well
  - Strong free cash flow*
- Gas Pipeline consistent
  - Steady performer with year-over-year growth
  - Major projects completed
  - Maintenance and regulatory spending decreasing after 2005
- Power reducing risk
  - Additional mid-term deals
  - Cash flow positive
  - Actuals tracking guidance

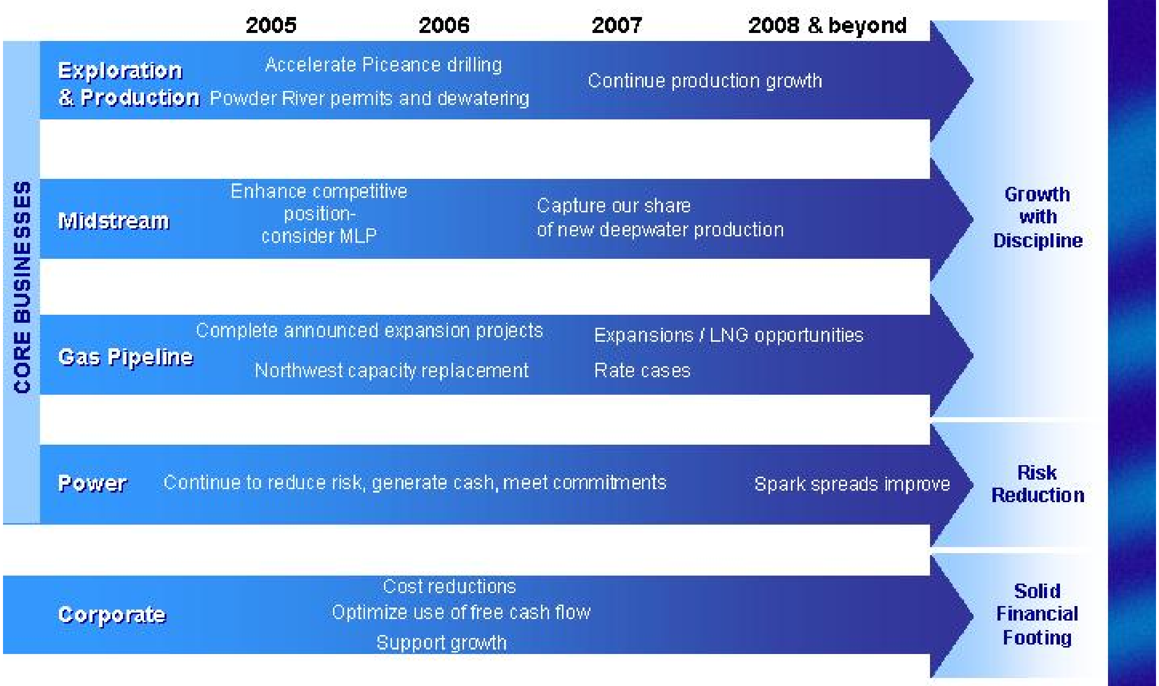
** Defined as segment profit plus DD&A less capital expenditures*

What You'll Hear

- Providing 2007 base case by business unit
- Opportunities included in our numbers
  - 12 rigs in Piceance; total production growth at 10-15% per year
  - Increasing utilization of existing deepwater projects
  - Rate cases improve segment profit in 2007
  - Selling megawatts primarily through mid-term contracts
- Potential upside on the horizon but not included in base case
  - Increasing Piceance rig count
  - New E&P opportunities
  - Major deepwater project
  - Major long-term power contracts
  - Natural gas price strength continues
  - NGL margins above the 5-year average
  - Spark spreads improving beyond current market
- Will refine guidance as move closer to 2007

Overview

The Road Ahead



2004 Financial Results

Don Chappel, CFO

Williams

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Financial Results

Dollars in millions (except per share amounts)	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Income (Loss) from Continuing Ops.*	$95	($73)	$93	($57)
Income (Loss) from Disc. Ops.*	(22)	20	71	327
Effect of Accounting Change	-	-	-	(761)
Net Income/(Loss)*	$73	($54)	$164	($492)
Net Income/(Loss) Share*	$0.13	($0.10)	$0.31	($1.01)
Rcr. Inc./(Loss) from Cont. Ops /Share**	$0.12	$0.11	$0.49	($0.03)
Rcr. Inc./(Loss) from Cont. Ops after MTM Adjustments/Share**	$0.09	$0.04	$0.35	($0.33)

* *Includes certain gains on asset sales and impairments and has been restated primarily for discontinued operations (See Notes 1 & 7 of the Financial Highlights). Reflects reclassification of Gulf Liquids to continuing operations.*

** *A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations and mark-to-market adjustments is available on Williams' Web site at www.williams.com and at the end of this presentation.*

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Recurring Income from Cont. Operations

Dollars in millions	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Income/(Loss) from Cont. Ops.	**$95**	**($73)**	**$93**	**($57)**
Gains on Sale of Assets	(10)	(16)	(10)	(337)
Impairments/Losses/Write-offs	31	106	70	357
Income (Expense) Related to Prior Periods	4	(9)	15	(117)
Debt Retirement Expenses	30	67	282	67
Insurance Arbitration Award	(103)	-	(103)	-
Other - Net	4	33	18	67
Less: Income Tax Provision	(17)	50	104	(34)
Recurring Income from Cont. Ops.	**$68**	**$58**	**$261**	**$14**
Preferred Dividend	-	-	-	(30)
Rec. Inc./(Loss) from Cont. Ops. Avail. to Com.	**$68**	**$58**	**$261**	**($16)**
Recurring Income/(Loss) from Cont. Ops/Share	**$0.12**	**$0.11**	**$0.49**	**($0.03)**

A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

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Recurring Income from Cont. Ops After Mark-to-Market Adjustments

Dollars in millions, except for per-share amounts	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Recurring income/(loss) from cont. ops avail. to common shldrs	**$ 68**	**$ 58**	**$ 261**	**$ (16)**
Recurring diluted earnings/(loss) per common share	**$ 0.12**	**$ 0.11**	**$ 0.49**	**$ (0.03)**
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM gains/losses	(23)	(85)	(304)	(262)
Add realized gains/losses from MTM previously recognized	(6)	25	186	8
Total MTM adjustments	(29)	(60)	(118)	(253)
Tax effect of total MTM adjustments (at 39%)	(11)	(23)	(46)	(99)
After tax MTM adjustments	(17)	(37)	(72)	(155)
Recurring income/(loss) from continuing operations avail. to common shareholders after MTM adjustments	**$ 51**	**$ 22**	**$ 190**	**$ (170)**
Recurring diluted earnings/(loss) per share after MTM adj.	**$ 0.09**	**$ 0.04**	**$0.35**	**$ (0.33)**

Note:

- *Adjustments have been made to reverse estimated forward unrealized MTM gains/losses and add estimated realized gains/losses from MTM previously recognized, i.e. assumes MTM accounting had never been applied to designated hedges and other derivatives.*
- *A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations after MTM adjustments is available on Williams' Web site at www.williams.com.*

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Net Income Components

Dollars in millions (except per share amounts)	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Segment Profit*	**$398**	**$153**	**$1,406**	**$1,239**
Net Interest Expense	(170)	(240)	(828)	(1,248)
Debt Retirement Expense	(30)	(67)	(282)	(67)
Other Income/(Expense) - Net	(14)	(15)	(72)	13
Income/(Loss) from Cont. Ops. Before Tax*	184	(169)	224	(63)
Provision/(Benefit) for Income Tax	89	(95)	131	(5)
Income/(Loss) from Continuing Ops.*	**$95**	**($73)**	**$93**	**($58)**
Income/(Loss) from Discontinued Ops.	(22)	20	71	327
Effect of Accounting Change	-	-	-	(761)
Net Income/(Loss)*	**$73**	**($54)**	**$164**	**($492)**

* *Includes certain gains on asset sales and impairments and has been restated primarily for discontinued operations (See Notes 1 & 7 of the Financial Highlights). Reflects reclassification of Gulf Liquids to continuing operations.*

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Fourth Quarter Segment Profit

Dollars in millions	Reported 4Q04	Reported 4Q03	Recurring 4Q04	Recurring 4Q03
Exploration & Production	$71	$50	$75	$50
Midstream Gas & Liquids(1)	236	64	151	64
Gas Pipeline	157	148	157	148
Power	(44)	(101)	(44)	12
Other	(22)	(8)	(10)	(7)
Segment Profit(2)	**$398**	**$153**	**$329**	**$267**
MTM Adjustments			(29)	(60)
Seg. Profit after MTM Adjustments			**$300**	**$207**

(1) Reflects reclassification of Gulf Liquids to continuing operations

(2) Reported segment profit includes certain gains on asset sales and impairments and has been restated primarily for discontinued operations (See Notes 1 & 7 of the Financial Highlights).
A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

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2004 Segment Profit

Dollars in millions	Reported		Recurring	
	2004	2003	2004	2003
Exploration & Production[1]	$236	$401	$251	$310
Midstream Gas & Liquids[2]	550	197	471	283
Gas Pipeline	586	555	595	582
Power[3]	77	135	77	(21)
Other	(43)	(51)	(13)	(10)
Segment Profit[4]	**$1,406**	**$1,239**	**$1,381**	**$1,144**
MTM Adjustments			(118)	(253)
Seg. Profit after MTM Adjustments			**$1,263**	**$891**

(1) E&P reported results include $15 million loss provision in 2004 related to prior periods and a gain on sale of $92 million in 2003.
(2) Reflects reclassification of Gulf Liquids to continuing operations
(3) Power 2003 reported results include $117 million income for prior period item correction.
(4) Reported segment profit includes certain gains on asset sales and impairments and has been restated primarily for discontinued operations (See Notes 1 & 7 of the Financial Highlights).
A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

Consolidated

Major Changes in Quarter Recurring Segment Profit After Mark-to-Market Adjustments

Dollars in millions

Recurring Segment Profit after MTM Adj. 4Q2003	**$207**
Exploration & Production	25
- Higher production volumes +$20 million	
- Higher net realized price +$2 million	
- Favorable international & transport +$4 million	
Midstream	87
- Higher NGL margins +$58 million	
- Improved olefins results +$26 million	
Gas Pipeline	9
- Lower G&A expenses +$7 million	
- Higher Gulfstream earnings +$3 million	
Power	(25)
- Lower realized MTM gains -$31 million	
- Higher realized margins +$1 million	
- Improved SG&A and Other +$4 million	
Other	(3)
Recurring Segment Profit after MTM Adj. 4Q2004	**$300**

Consolidated

Major Changes in Year Recurring Segment Profit After Mark-to-Market Adjustments

Dollars in millions

Recurring Segment Profit after MTM Adj. 2003	**$891**
Exploration & Production	(59)
- Higher production volumes +$14 million	
- Lower net realized price -$26 million	
- Higher operating costs -$22 million	
- 2003 mark-to-market gain -$24 million	
Midstream	188
- Higher NGL margins +$60 million	
- Higher NGL volumes +$45 million	
- Improved domestic olefins +$41 million	
- Improved Canadian olefins +$25 million	
Gas Pipeline	13
- Transco & NWP expansion +$37 million	
- Higher interruptible transport +$14 million	
- Higher net expenses -$18 million	
Power	233
- Higher realized MTM gains +$178 million	
- Higher realized margins +$8 million	
- Lower SG&A, Op. costs and other +$48 million	
Other	(3)
Recurring Segment Profit after MTM Adj. 2004	**$1,263**

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Consolidated

Cash Information

Dollars in millions	4Q04	Year
Beginning Unrestricted Cash *	**$976**	**$2,318**
Cash Flow from Continuing Operations	404	1,473
Cash Flow from Discontinued Operations	(3)	16
Asset Sales	40	1,053
Restricted Investments (LC Collateral)	-	380
Debt Issuance (Transco)	75	75
Debt Retirements	(230)	(3,267)
Capital Expenditures/Investments	(249)	(790)
Debt Premiums/Issuance Costs	(33)	(273)
Dividends	(28)	(43)
Other-Net	(22)	(12)
Ending Unrestricted Cash *	**$930**	**$930**
Unrestricted Cash at 2/19/05		**$1,332**
Restricted Cash at 12/31/04 (not included above)	**$113**	**$93**

** Includes cash for discontinued operations of $2.5 million at 12/31/03 and $0 million at 12/31/04*

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Debt Balance

Dollars in millions		*Avg. Cost*
Debt Balance @ 12/31/03 *	**$11,978**	**7.7%**
Scheduled Debt Retirements & Amortization	(831)	
Tendered Debt Retirements	(2,991)	
Open Market Purchases	(269)	
Debt Issuance (Transco)	75	
Debt Balance @ 12/31/04	**$7,962**	**7.4%**
Less: Scheduled January Retirements	**(200)**	
Debt Balance @ 1/31/05	**$7,762**	
Fixed Rate Debt @ 12/31/04	**$7,300**	**7.6%**
Variable Rate Debt @ 12/31/04	**$662**	**4.5%**

** Debt is long-term debt due within 1 year plus long-term debt plus notes payable; includes FELINE PACS*

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2004 vs. Guidance

Dollars in millions, except per-share amounts	**2004**	**Nov. 4 Guidance**
Segment profit	**$1,406**	**$1,175 - $1,375**
Net Interest Expense	(828)	(810) – (860)
Early Debt Retirement Costs	(282)	(300) – (250)
Other (Primarily General Corp. Costs)	(72)	(90) – (125)
Pretax Income (Loss)	$224	($25) - $140
Provision (Benefit) for Income Tax	(131)	0 – (80)
Income / (Loss) from Continuing Ops	$93	($25) – $60
Income from Discontinued Ops	71	50 – 100
Net Income	**$164**	**$25 – $160**
Diluted EPS	**$0.31**	**$0.05 - $0.30**
Net Income – Recurring *	**$261**	**$183 – $238**
Diluted EPS – Recurring *	**$0.49**	**$0.34 - $0.44**
Diluted EPS- Recurring After MTM Adjustments	**$0.35**	**$0.26 - $0.36**

** Excludes early debt retirement costs, gains and losses on assets sales and impairments*

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EPS Metrics

2004	1Q	2Q	3Q	4Q	Total	*11/4/04 Guidance*
EPS	$0.02	($0.03)	$0.19	$0.13	$0.31	*$0.05 - 0.30*
Recurring EPS	0.01	0.10	0.26	0.12	0.49	*0.34 - 0.44*
Rec. EPS after MTM Adj.	**0.14**	**0.03**	**0.09**	**0.09**	**0.35**	*0.26 - 0.36*
Average Shares (MM)	519	522	530	586	536	

2003	1Q	2Q	3Q	4Q	Total
EPS	($1.59)	$0.47	$0.20	($0.10)	($1.01)
Recurring EPS	(0.10)	(0.03)	-	0.11	(0.03)
Rec. EPS after MTM Adj.	**(0.12)**	**(0.25)**	**0.01**	**0.04**	**(0.33)**
Average Shares (MM)	518	525	525	519	518

Business Unit Results

Exploration & Production

Ralph Hill, Senior Vice President

Williams

Exploration & Production

Segment Profit

Dollars in millions	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Segment Profit	**$71**	**$50**	**$236**	**$401**
Non recurring:				
Ownership issue	4	-	15	-
Gain on sale of assets	-	-	-	(91)
Recurring Segment Profit	**$75**	**$50**	**$251**	**$310**

- 4Q03 to 4Q04 increase includes
  - Volume increase of 25%
  - Recurring profit increase of 50%
- Base business sequential quarter improved
  - Volumes increased by 5%
  - Recurring profit increased 7%
- $91mm negative hedge impact in 4th quarter, $250mm negative hedge impact full year

Strong 2004 Reserves Performance

- Domestic proved reserves up 10.5% to 3.0 Tcfe
- Total proved reserves 3.2 Tcfe
- 248% reserves replacement
- 99% success rate
- Moved 451 Bcfe to proven

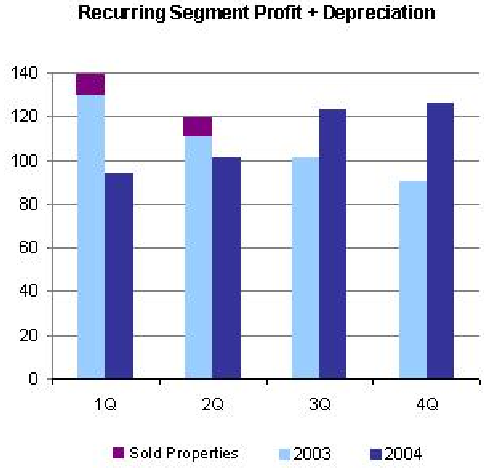
Transfers of Probable to Proved (Bcf)

	2002	2003	2004	Total
Total for retained basins	313	408	451	1,172

Exploration & Production

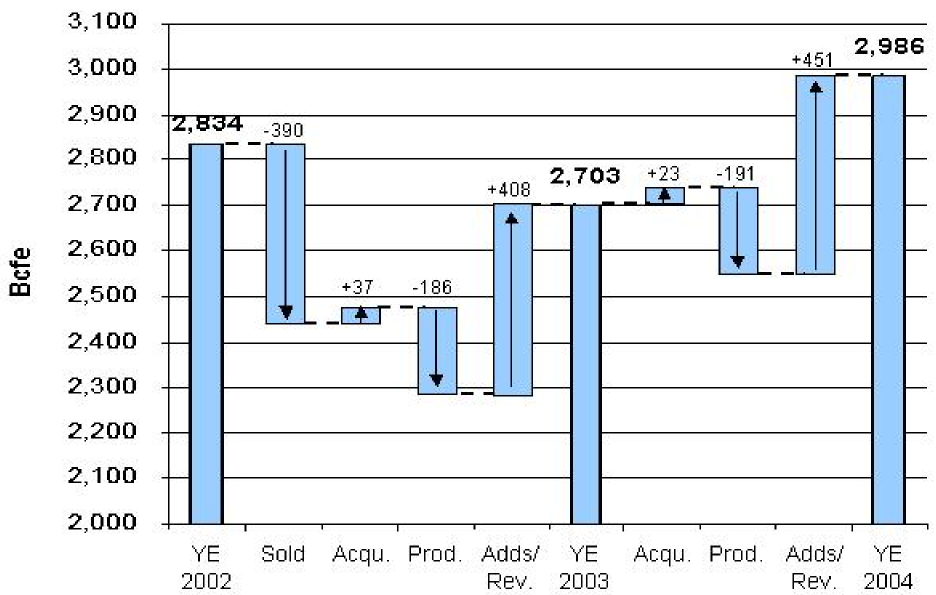
2004 Accomplishments

- 4Q 2004 production up 25% or 121 MMcfed since 4Q'03
- Strong reserves performance
- $0.92 2004 F&D cost, much better than industry average
- Record capital program successfully executed
- Additional Piceance downspacing approved
- Drilling initiated in new Piceance areas of Trail Ridge and Ryan Gulch
- Received environmental awards from EPA, COGCC, and BLM



Exploration & Production

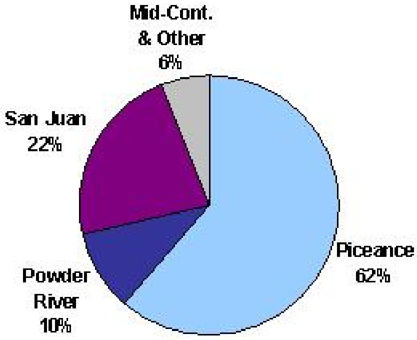
Domestic Proved Reserves Reconciliation



Exploration & Production

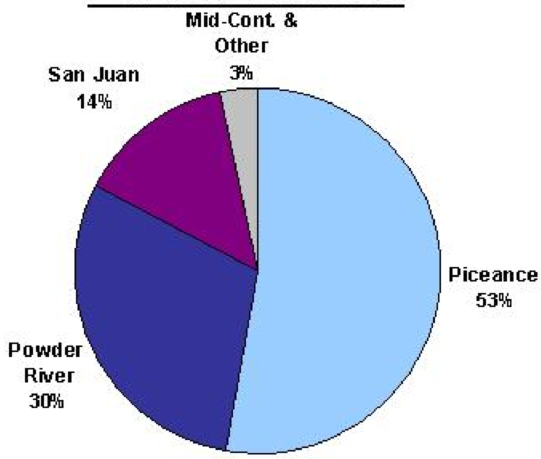
Domestic Reserves

2004 Year End Proved Reserves



Total: 3.0 Tcf Proved*

Proved, Probable & Possible Reserves



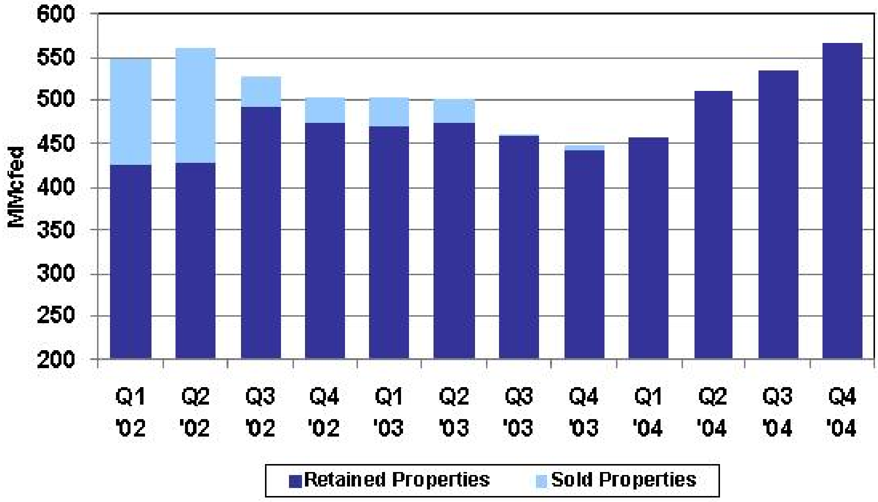
Total: ~7 Tcf Proved, Probable & Possible **

* *99% of proved reserves were audited or prepared by Netherland, Sewell & Assoc., Inc. or Miller and Lents, LTD.*

** *Please reference E&P oil & gas reserves disclaimer concerning reserves estimates. Excludes new opportunities such as Trail Ridge, Ryan Gulch, Red Point.*

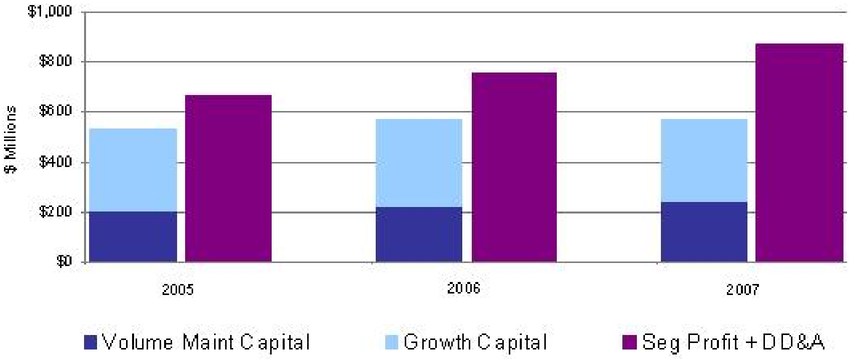
Exploration & Production

Domestic Production Growth



Exploration & Production

Growth Metrics



Note: Assumes mid-point of guidance range

U.S. Natural Gas Production

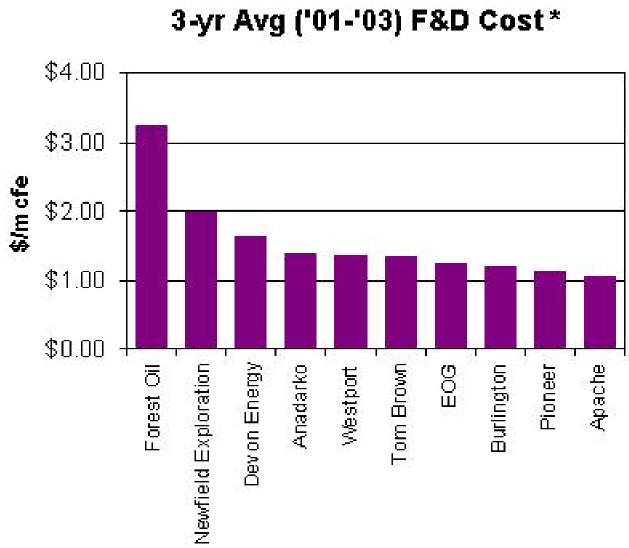
Company	4Q 2003	4Q 2004	% Change
	MMcf/d		
BP	2,933	2,651	-10%
ExxonMobil	2,038	1,810	-11%
ChevronTexaco	2,110	1,618	-23%
ConocoPhillips	1,469	1,377	-6%
Shell Group (RD)	1,397	1,302	-7%
Sub-total	**9,947**	**8,758**	**-12%**
Devon Energy Corp.	1,748	1,620	-7%
Anadarko Petroleum	1,365	1,306	-4%
Kerr-McGee*	632	1,041	65%
Burlington Resources Inc.	870	916	5%
XTO (Cross Timbers)*	738	916	24%
EOG Resources	632	666	5%
Apache Corp.	686	637	-7%
Marathon	737	585	-21%
Newfield Exploration*	501	585	17%
Williams	**447**	**566**	**27%**
Pioneer Natural Resources*	454	547	21%
Occidental	525	499	-5%
Unocal	566	470	-17%
Questar	270	300	11%
Amerada Hess	213	178	-16%
Sub-total	**10,384**	**10,830**	**4%**
TOTAL	**20,331**	**19,588**	**-3.7%**

Source: www.evaluateenergy.com and company press releases ** Completed major acquisitions in 2004*

Exploration & Production

Finding & Development Cost Comparison

- Williams' 2004 F&D cost was $0.92 per mcfe. The 3-yr Avg ('02-'04) was $0.78
- Industry rolling average F&D cost through 2003 was $1.42 per mcfe
- Expect industry average to increase due to higher 2004 drilling cost and acquisition activity



* Source: RBC Capital Markets Research Comment, dated March 15, 2004

2005-2007 Guidance

Dollars in millions	2005	2006	2007
Segment profit	$400 - 475	$450 - 525	$500 - 625
Annual DD&A	$220 - 250	$250 - 290	$300 - 350
Segment Profit + DD&A	$620 - 725	$700 - 815	$800 - 975
Capital spending	$500 - 575	$525 - 625	$525 - 675
Production (MMcfe/d)	600 - 700	700 - 800	775 - 875
Hedged Volume (MMcfe/d)	286	298	172
Hedged Price (NYMEX)	$4.44	$4.39	$4.20

Key Points

- Strong 2004 reserves performance
- Significant volume growth from existing positions
- Continuing to expand development drilling activity – Piceance is primary growth driver
- Decreased hedging increases upside
- Long history of high drilling success, low finding costs
- Short time cycle investments, fast cash returns
- Maintaining top quartile cost and efficiency position
- Long-term repeatable drilling inventory of significant proved undeveloped, probables, and possibles
- Exciting new Piceance area opportunities

Midstream

Alan Armstrong, Senior Vice President

Williams

Midstream

Segment Profit

Dollars in millions	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Segment Profit	**$236**	**$64**	**$550**	**$197**
Non recurring:				
Depreciable Life Adjustment	1	-	7	4
Impairments	17	16	17	109
Insurance Arbitration Award	(94)	-	(94)	-
Gain on Asset Sales	(9)	(16)	(9)	(27)
Recurring Segment Profit	**$151**	**$64**	**$471**	**$283**

2004 vs. 2003 increase includes
- $60 million due to higher NGL margins
- $45 million increased NGL volumes
- $41 million improvement in domestic olefins
- $25 million improvement in Canada olefins

4Q04 vs. 4Q03 increase includes
- $58 million increase in NGL margins and volumes
- $26 million due to better performance in olefins

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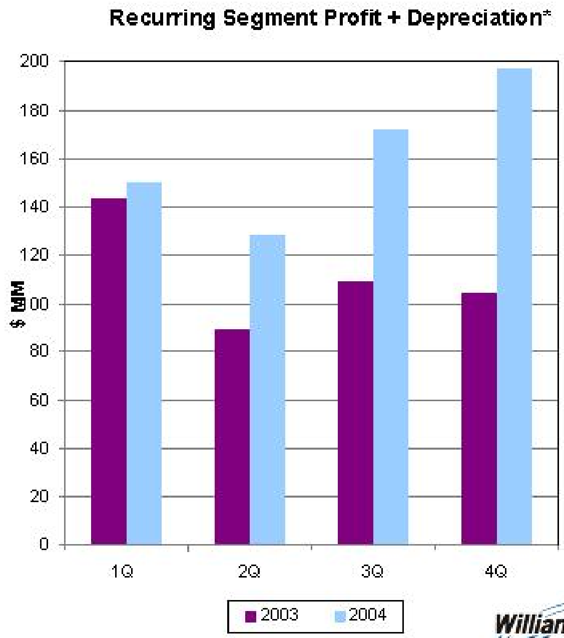
Note:Reflects reclassification of Gulf Liquids to continuing operations

Midstream

4th Quarter and 2004 Accomplishments

- Record recurring earnings
- Record domestic NGL production:
  - 2004 record year
  - 4Q record quarter
  - December record month
- Record number of well connects in 2004 (> 500)
- Devil's Tower start-up (twice)
- Opal TXP-IV Expansion
- Asset sales
- Gulf Liquids insurance arbitration award finalized and LOI signed on Gulf Liquids asset sales



* Excludes gains/losses/impairments

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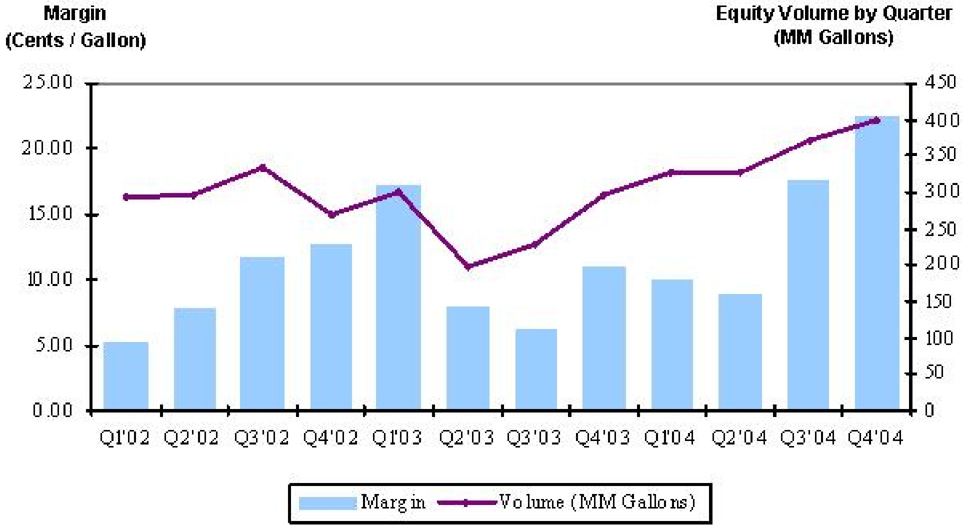
Midstream

Margins Above Average

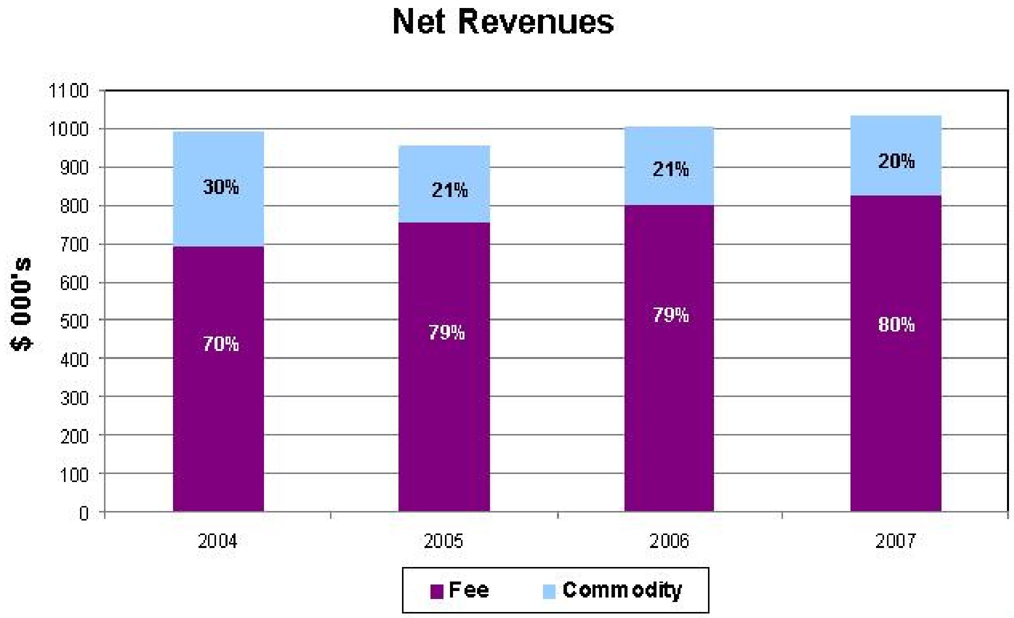
Domestic NGL Actual Average Net Margin and Volume by Quarter



Note: Based on actual realized prices, contractual obligations, shrink, fuel, actual equity liquids percentages, etc.

Midstream

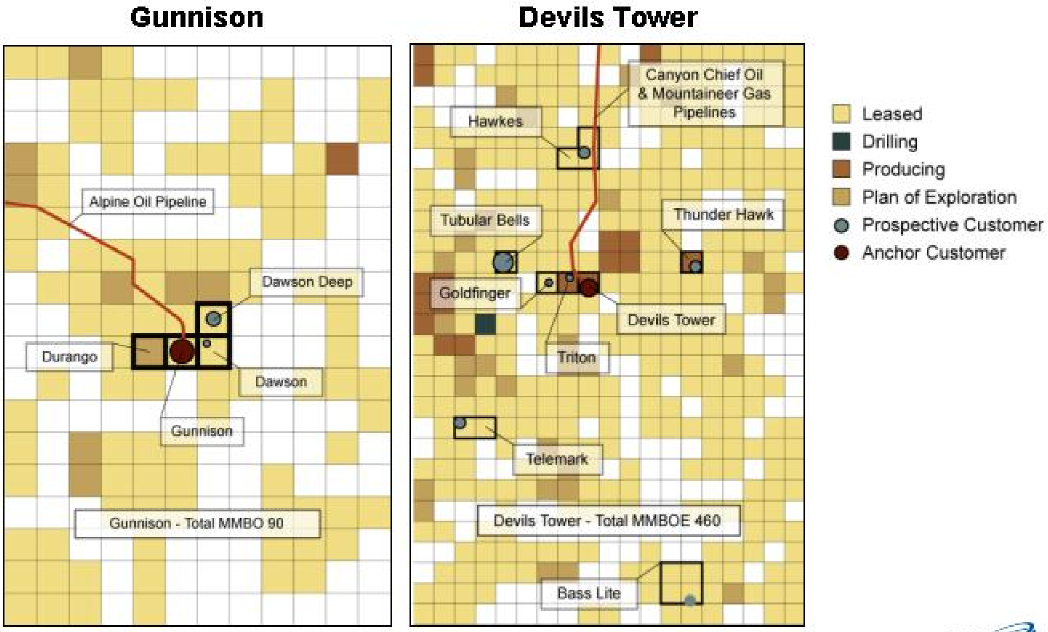
Fee-Based Bedrock of Earnings



Note: Total revenues less cost of goods sold. Reflects 5 year average (Jan '00 – Dec '04) margins in 2006-2007 at mid-point of range.

Midstream

Deepwater Success-What to Watch For



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Midstream

2005-2007 Guidance

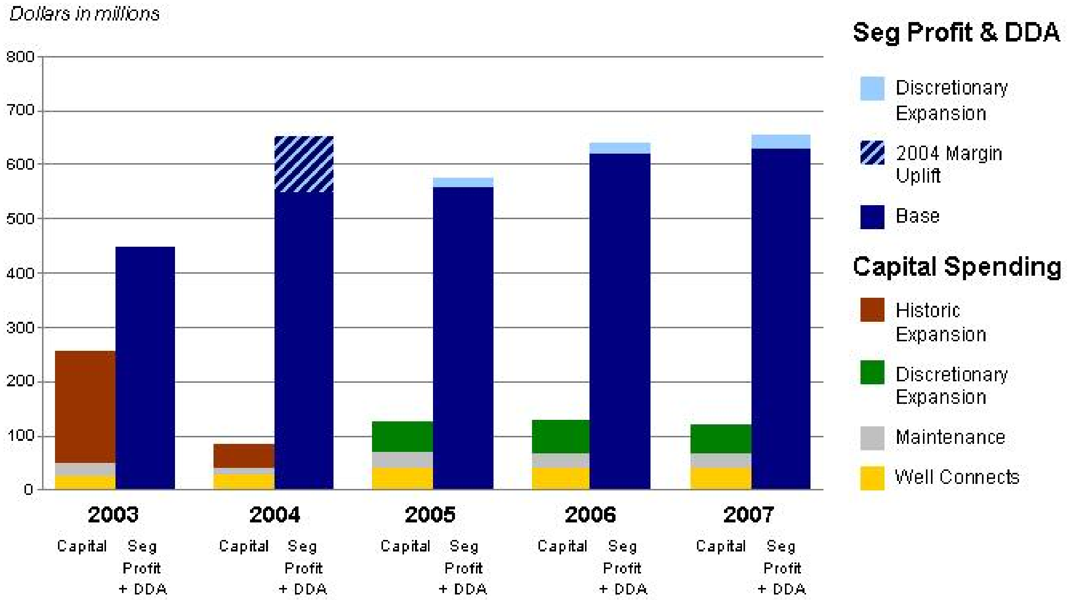
Dollars in millions	2005	2006	2007
Segment Profit	$350-430 *$310 - $410*	$400-500	$400-520
Annual DD&A	$180-190	$185-195	$190-200
Segment Profit + DDA	$530-620	$585-695	$590-720
Capital Spending	$120-140	$110-130	$100-130

Note:

- ***Guidance does not include any major deepwater projects***
- *If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below*

Midstream

Strong Free Cash Flow



Note:
- Segment Profit is stated on a recurring basis. Segment Profit for 2003 & 2004 has been restated to reflect reclassifications
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges.
- 2004 margin uplift represents actual realized margin in excess of forecasted average margins.

Midstream

Key Points

- Business generated record segment profit in 2004
- Operational high marks set
- Continued strong free cash flows
- Deepwater cash flows:
  - – Continued strength
  - – Upside driven by drill-ship availability
- One-two punch
  - Premier assets in growth basins
  - Attracting volumes through reliability

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Gas Pipeline

Phil Wright, Senior Vice President

Gas Pipeline

Segment Profit

Dollars in millions	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Segment profit	**$157**	**$148**	**$586**	**$555**
Includes:				
Write-off software project	-	-	-	26
Severance accrual	-	-	-	1
Write-off of previously capitalized cost for idled segment	-	-	9	-
Recurring Segment Profit	**$157**	**$148**	**$595**	**$582**

4Q04 vs. 4Q03 increase includes

- $7 million due to lower G&A expenses
- $3 million due to increased Gulfstream earnings

2004 vs. 2003 increase includes

- $37 million due to full year of Transco and Northwest expansion projects
- $14 million due to higher interruptible transportation revenue
- ($18) million due to higher net expenses

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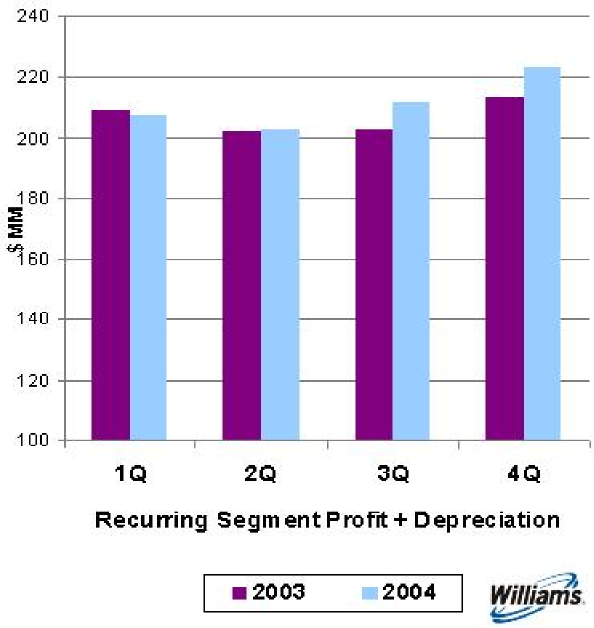
Gas Pipeline

Fourth Quarter Accomplishments

- Everett Delta in-service Nov. 10, 2004
- 26-inch Replacement project filed with FERC
- Northwest receives Environmental Excellence Award associated with the Evergreen Project
- Transco set peak day delivery record in December



Gas Pipeline

Major Project Update

- Northwest Pipeline Replacement
  - Filed Certificate Application on November 29, 2004
  - Capital ≈ $333 million
  - In-service date, November 2006
- Central New Jersey
  - FERC Certificate issued February 10, 2005
  - Capital ≈ $13 million
  - In-service date, November 2005
- Leidy to Long Island
  - Pre-filing process underway
  - Capital ≈ $100 million
  - In-service date, November 2007

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Gas Pipeline

Gulfstream Update

- Phase II placed in-service February 1st 2005
- Project specifics
  - 109-mile, 30" extension to serve Florida Power & Light's Martin plant
  - 350 Mdth/d, long-term commitment by FPL
  - Cost ≈ $225 million
- Capacity under long-term contract
  - Today: 305 Mdth/d (28% of capacity)
  - Mid-2005: 705 Mdth/d (64% of capacity)

Future Rate Cases

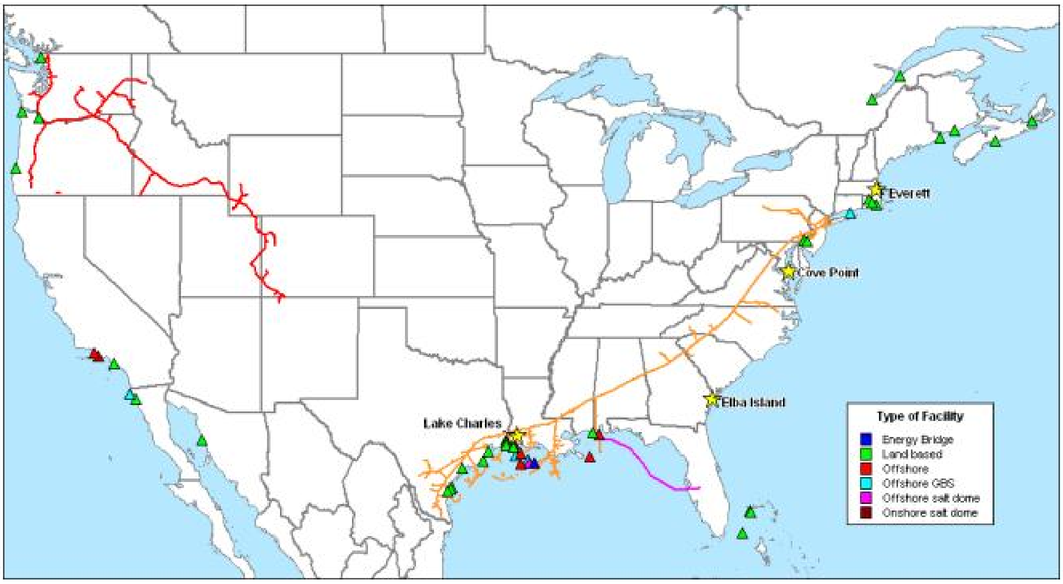
- Northwest
  - Next anticipated rate case effective 1Q07
    - 26" capacity replacement primary driver
  - Last rate case effective March 1997
  - No requirement to file
- Transco
  - Next rate case effective 1Q07
  - Last rate case effective September 2001
  - Required to file

Accommodating Imported LNG

- Expansions on existing LNG Facilities
- WGP advantages
  - Serves markets that are large, diverse, and growing
  - Proximity to anticipated Gulf Coast LNG
  - Delivery flexibility
  - Low rates
- Challenges
  - Maintaining gas quality
  - Maintaining flexibility

Gas Pipeline

Proposed and Existing LNG Importation Facilities



Gas Pipeline

2005-2007 Guidance

Dollars in millions	2005	2006	2007
Segment profit	$545 - 585[1] *$525 - 575*	$515 – 565[1,2] *$525 - 575*	$575 - 635[1,2]
Annual DD&A	280 - 290	290 – 300	300 - 310
Segment profit + DDA	725 – 875	805 – 865	875 - 945
Capital spending	370 - 420	475 - 550	250 - 325

1) *Duke has given notice to terminate their contract related to the Gray's Harbor project and pay Williams a lump sum amount related to the net costs of the project and related income taxes. To date, no formal agreement has been signed. If there is an agreement, the above segment profit range will be adjusted accordingly.*

2) *Refinancing and additional leverage of Gulfstream is reflected in these amounts. Depending on the timing and amount financed this reflects a decrease from previous guidance of between $10-20 million.*

Note: If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below

Gas Pipeline

2005-2007 Capital Spending Detail

Dollars in millions	2005	2006	2007
Normal Maintenance	$145 - 165	$95 - 130	$95 - 130
Major Regulatory Compliance	160 - 170	95 - 115	85 - 105
NWP 26" Replacement	48	276	2
Expansion	20 - 30	10 - 20	70 - 90
Total	**$370 - 420**	**$475 - 550**	**$250 - 325**

Note:
- Major regulatory compliance includes Pipeline Safety and Clean Air Act expenditures as detailed in the 2003 Form 10-K
- Amounts include AFUDC
- Sum of ranges may not add due to rounding

Key Points

- Record segment profit in 2004
- Rate case preparation in full swing
- Achieving substantial progress in compliance and reliability investments
- Transco expansions continue
- Focused on maintaining low-cost provider status
- Strong free cash flow generator
- Stable, low-risk earnings

Power

Bill Hobbs, Senior Vice President

Power

Segment Profit

Dollars in millions	4th Quarter 2004	4th Quarter 2003	Year 2004	Year 2003
Gross Margin	($16)	$40	$185	$238
SG&A & Other	(24)	(17)	(79)	(129)
Op. Exp. & Other Inc / (Exp)	(4)	(124)	(29)	26
Segment Profit	**($44)**	**($101)**	**$77**	**$135**
Includes:				
Asset Impairments	-	89	-	103
CA Refund & Other Accrual Adj.	-	33	-	33
Prior period correction*	-	(9)	-	(117)
Regulatory Settlement	-	-	-	20
Gains on sale of assets/contracts	-	-	-	(208)
Reduction in force costs	-	-	-	13
Recurring Segment Profit	**($44)**	**$12**	**$77**	**($21)**

** 2003 amounts reflect corrections as disclosed in 2003 10-K*

Power

2004 & Recent Accomplishments

- Success in signing risk-reducing contracts
  - Contracted re-sale of tolls of 550 MW with 1-3 year terms
  - Sale of capacity of 650 MW in 2005
- Realized significant free cash flow
- Reduced risk of portfolio
- Adopted hedge accounting, reducing earnings volatility
- Retained top talent
- Maximized E&P netbacks by maximizing storage and transport contracts

Segment Profit after MTM Adjustment

Dollars in millions

Combined Power Portfolio *Estimated as of 12/31/04*	4Q04 A	4Q04 F	2004 A	2005 F	2006 F	2007 F
Net Revenues	68	41	582	281	364	435
Tolling Demand Payment Obligations	(84)	(84)	(397)	(395)	(399)	(404)
Gross Margin	(16)	(43)	185	(115)	(35)	31
SG&A & Other Inc / (Exp)	(28)	(31)	(108)	(68)	(65)	(66)
Segment Profit	(44)	(74)	77	(183)	(100)	(35)
MTM Adjustments:						
Reverse Forward Unrealized MTM (Gains) / Losses	(23)		(304)			
Add Realized Gains / (Losses) from MTM Previously Recognized	(6)		186			
Add Expected Realization of Prior Period MTM Gains / Losses						
Designated Hedges		83		274	99	(23)
All Other Derivatives		(63)		9	154	189
MTM Adjustments	**(29)**	**20**	**(118)**	**283**	**253**	**166**
Segment Profit after MTM Adjustment	**(73)**	**(54)**	**(41)**	**100**	**153**	**131**

[1]*Schedule of expected realization of MTM gains/losses previously recognized from designated Hedges is included in the Appendix.*

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Power

Segment Profit to Cash Flow

Dollars in millions

	4th Quarter 2004				
	Power & Natural Gas	Legacy*	Other	Total	2004
Gross Margin	($17)	$1		($16)	$185
SG&A & Other	(24)			(24)	(79)
Oper Exp & Other Inc / (Exp)			(4)	(4)	(29)
Segment Profit	($41)	$1	($4)	($44)	$77
MTM Adjustments:					
Reverse Forward Unrealized MTM (Gains) / Losses	(23)	0		(23)	(304)
Add Realized Gains / (Losses) from MTM previously recognized	23	(29)		(6)	186
Segment Profit after MTM Adjustments	($41)	($28)	($4)	($73)	($41)
Total Working Capital			129	129	606
Power Segment CFFO	($41)	($28)	$125	$56	$565
Est. Working Capital (Recv'd)/Used for Other BU's			36	36	(276)
Power Segment Standalone CFFO	($41)	($28)	$161	$92	$289

*Includes liquidation of Interest Rate and Crude & Refined Products portfolios.

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Power

Cash Flow Variance Analysis

Undiscounted dollars in millions

Combined Power Portfolio *Actual Q4'04 v. Forecast Q4'04*	4Q04 A	4Q04 F	2004 A	2004 F
Tolling Demand Payment Obligations	($84)	($84)	($397)	($391)
Resale of Tolling	39	39	144	143
Full Requirements	4	4	12	16
Long-term Physical Forward Power Sales	6	12	72	97
OTC Hedges	53	51	170	168
Estimated Merchant Cash Flows	19	12	140	114
Total Cash Flows	$37	$34	$141	$147
Working Capital	37	(92)	503	364
SG&A and Other	(24)	(23)	(79)	(82)
Estimated Cash Flows After SG&A	$50	($81)	$565	$429

Note: Q4 2004 forecast estimated as of 9/30/04. Q4 2004 Actual cash flows agree in total with Power's Cash Flow Statement; however the allocation of actual cash flows to the various deal types is based on estimates.

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2005-2007 Guidance

Dollars in millions

	2005	2006	2007
Segment Profit/(Loss)	**($250) – (150)** *($200) – (100)*	**($200) – (50)**	**($100) – 50**
MTM Adjustments	**300** *254*	**250** *269*	**150**
Segment Profit after MTM Adj.	**50 - 150** *100*	**50 – 200** *154*	**50 - 200**
Cash Flow from Operations	**50 - 150**	**50 – 200**	**50 - 200**
Capital Expenditures	**-**	**-**	**-**

Note: If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below

Key Points

- CFFO expected to remain positive
- Refocused efforts to offer risk management to customers -- deals getting done
- Continuing to see improvements in
  - Market liquidity
  - Spark spreads
  - Williams credit
- Focus remains on reducing risk through longer-term sales
- Factors impacting guidance
  - Spark spread movement up or down
  - Capacity market timing and value
  - New long-term contracts

2005-2007 Consolidated Outlook

Don Chappel, CFO

2005 Segment Profit Guidance

Dollars in millions	**2005**
Exploration & Production	400 - 475
Midstream	350 - 430 *310 - 410*
Gas Pipeline	545 - 585 *525 - 575*
Other/Rounding	5 - 10 *15 - (10)*
	$1,300 - 1,500 *1,250 - 1,450*
Power	(250) - (150) *(200) - (100)*
Seg. Profit before MTM Adj.	$1,050 - 1,350
MTM Adjustments	300 *254*
Seg. Profit after MTM Adjust.	$1,350 - 1,650 *1,300 - 1,600*

Note: If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below.

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2005 Interest Expense Guidance

Dollars in millions	2005
Interest on Long-Term Debt	$555 - 575
Amortization Discount/Premium and other Debt Expense	25
Credit Facilities: (incl. Commitment Fees plus LC Usage)	30 - 40
Interest on other Liabilities	20 - 30
Interest Expense	$630 - 670
Less: Capitalized Interest	(5) - (10)
Net Interest Expense Guidance	**$625 - 660**

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2005 Forecast Guidance

Dollars in millions, except per-share amounts	2005
Segment profit before MTM adjustment	**$1,050 - $1,350**
Net Interest Expense	(625) - (660)
Other (Primarily General Corp. Costs)	(90) - (125)
Pretax Income	335 - 565
Provision for Income Tax	(155) - (245)
Income from Continuing Ops	180 - 320
Income/(Loss) from Discontinued Ops	(5) - 5
Net Income	**$175 - 325**
Diluted EPS	**$0.31 - $0.57**
Recurring Income from Cont. Ops	**$180 - $320**
Diluted EPS – Recurring	**$0.31 - $0.56**
Diluted EPS- Recurring After MTM Adjustments (1)	**$0.63 - $0.88**

(1) Includes MTM adjustment of $300 million (pretax)

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2005-2007 Segment Profit

Dollars in millions	2005	2006	2007
Exploration & Production	$400 - 475	$450 - 525	$500 - 625
Midstream	350 - 430 *310 - 410*	400 - 500	400 - 520
Gas Pipeline	545 - 585 *525 - 575*	515 - 565 *$525 - 575*	575 - 635
Power	(250) - (150) *(200) – (100)*	(200) - (50)	(100) - 50
Other/Corp.	5 - 10 *15 - (10)*	35 - (40) *25 - (50)*	0 - (30)
Total	**$1,050 - 1,350**	**$1,200 - 1,500**	**$1,375 - 1,800** *$1,300*
MTM Adjustment	300	250	150
Total After MTM Adj.	**$1,350 - 1,650** *$1,300 - 1,600*	**$1,450 - 1,750**	**$1,525 - 1,950**

Note: If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below

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2005 - 2007 Outlook

Dollars in millions	2005	2006	2007
Segment Profit			
Reported Seg. Profit	$1,050 - 1,350	$1,200 - 1,500	$1,375 - 1,800 *1,300*
MTM Adjustment	300	250	150
After MTM Adjust.	1,350 - 1,650 *1,300 – 1,600*	1,450 - 1,750	1,525 - 1,950
DD&A	700 - 775	750 - 850	800 - 900
Cash Flow from Ops.	1,300 - 1,600	1,450 - 1,750	1,600 - 1,900
Capital Expenditures	1,000 - 1,200	1,150 - 1,350	900 - 1,100 *900 - 1,200*
Free Cash Flow (1)	300 - 400	300 - 400	700 - 800
Effective Tax Rate (2)	39%	39%	39%
Cash Tax Rate	3 - 5%	4 - 8%	5 - 10%

(1) Free cash flow is defined as cash flow from operations less capital expenditures, before dividend or principal payments
(2) An additional $25 million income tax expense is forecast in 2005 – 2007
Note: If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below

Consolidated

Drivers

Dollars in millions	Segment Profit Low	Segment Profit High	CFFO Low	CFFO High
2004	1381[1]	1381[1]	1,473	1,473
Interest Savings	-	-	220	260
Midstream - Lower NGL Margins	(100)	-	(100)	-
- Deepwater Increase	30	50	30	50
Changes in Power[2]	(325)	(225)	-	100
E&P - Price Changes	85	95	85	95
- Volume Increases	85	95	110	120
Margins / Adequacy Assurances	-	-	(450)	(350)
Other	1,275	1,335	(68)	(148)
2005	1,050	1,350	1,300	1,600
Interest Savings	-	-	10	30
Changes in Power	50	100	-	100
Increase in Deepwater	35	50	35	50
E&P - Price Changes	(30)	(20)	(30)	(20)
- Volume Increases	70	80	90	100
Other	25	(60)	45	(110)
2006	1,200	1,500	1,450	1,750
Changes in Power	100	150	-	-
Increase in Gas Pipes	60	70	60	70
Increase in Deepwater	-	30	-	30
E&P - Price Changes	(60)	(40)	(60)	(40)
- Volume Increases	90	110	110	130
Other	(15)	(20)	40	(40)
2007	1,375	1,800	1,600	1,900

[1] Recurring

[2] Primarily represents the 2004 MTM reversal

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2005 - 2007 Capital Expenditures

Dollars in millions	2005	2006	2007
Exploration & Prod.	**$500 - 575**	**$525 - 625**	**$525 - 675**
Midstream	**120 - 140**	**110 - 130**	**100 - 130**
Gas Pipeline	**370 - 420**	**475 - 550**	**250 - 325**
Power	**-**	**-**	**-**
Other/Corporate	**10 - 30**	**10 - 30**	**10 - 30**
Total	**$1,000 - 1,200**	**$1,150 - 1,350**	**$900 - 1,100** *1,200*

Notes:
- Sum of ranges for each business line does not necessarily match total range
- If guidance has changed, previous guidance from 11/4/04 is shown in italics directly below

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2005-2007 Maintenance vs. Growth Capital

Dollars in millions	2005	2006	2007
Explor. & Prod.			
Growth	310 - 365	315 - 395	295 - 425
Maintenance	190 - 210	210 - 230	230 - 250
Total	500 - 575	525 - 625	525 - 675
Midstream			
Growth	60 - 75	60 - 75	50 - 70
Maintenance	60 - 65	50 - 55	50 - 60
Total	120 - 140	110 - 130	100 - 130
Gas Pipeline			
Growth	20 - 30	10 - 20	70 - 90
Maintenance	350 - 390	465 - 530	180 - 235
Total	370 - 420	475 - 550	250 - 325
Power	-	-	-
Other/Corp - Maint.	10 - 30	10 - 30	10 - 30
Total:			
Growth	390 - 470	385 - 490	415 - 585
Maintenance	610 - 695	735 - 845	470 - 575
Total	1,000 - 1,200	1,150 - 1,350	900 - 1,100 *1,200*

Note:
- Sum of ranges for each business line does not necessarily match total range

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2004 – 2005 Return on Capital Employed

Dollars in millions	2003		2004		2005FC
Total Assets	27,022		24,070		24,100
Non-interest Bearing Liabilities	10,939		11,136		11,200
Capital Employed (Net Assets)	**16,083**		**12,934**		**12,900**
Average Capital Employed (Net Assets)		**14,509**		**12,917**	

	2004A	2005 Low	2005 High
Return:			
Net Income (Recurring Proforma After MTM Adjustments)	190	363	503
After Tax Net Interest Expense (at 39%)	505	381	403
Return	695	744	906
Average Capital Employed (Net Assets)	14,509	12,917	
Return on Avg. Capital Employed (Net Assets)	**4.8%**	**5.8%**	**7.0%**
Estimated Percentage Improvement from 2004 to 2005		**20.3%**	**46.3%**

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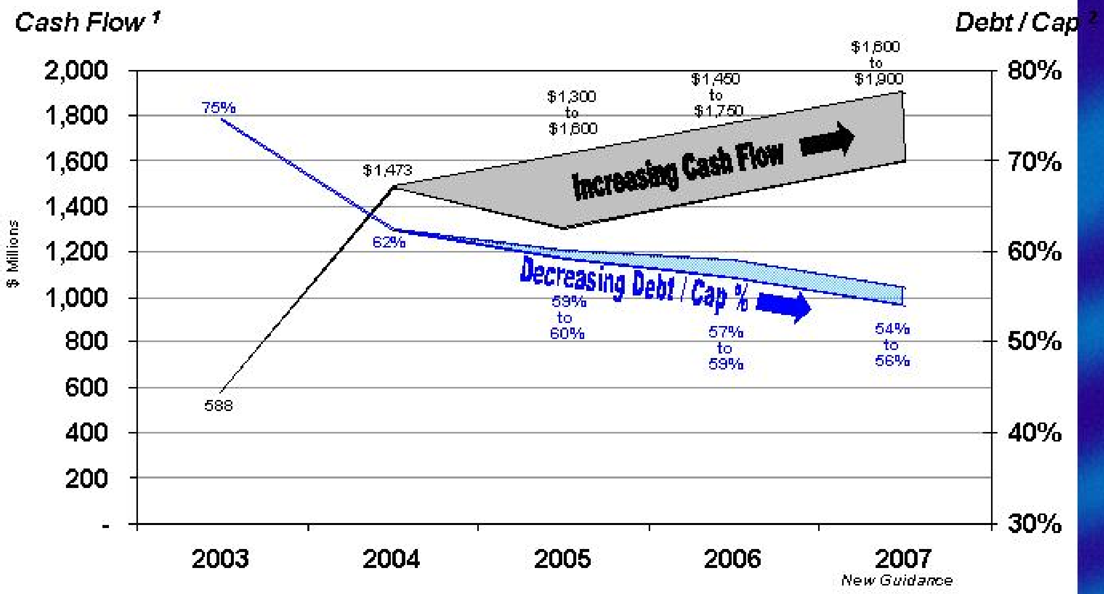
Steady Improvement . . .



[1] Cash Flow from Continuing Operations (CFFO)

[2] Debt to Capitalization = Total Debt / (Total Debt + Equity)

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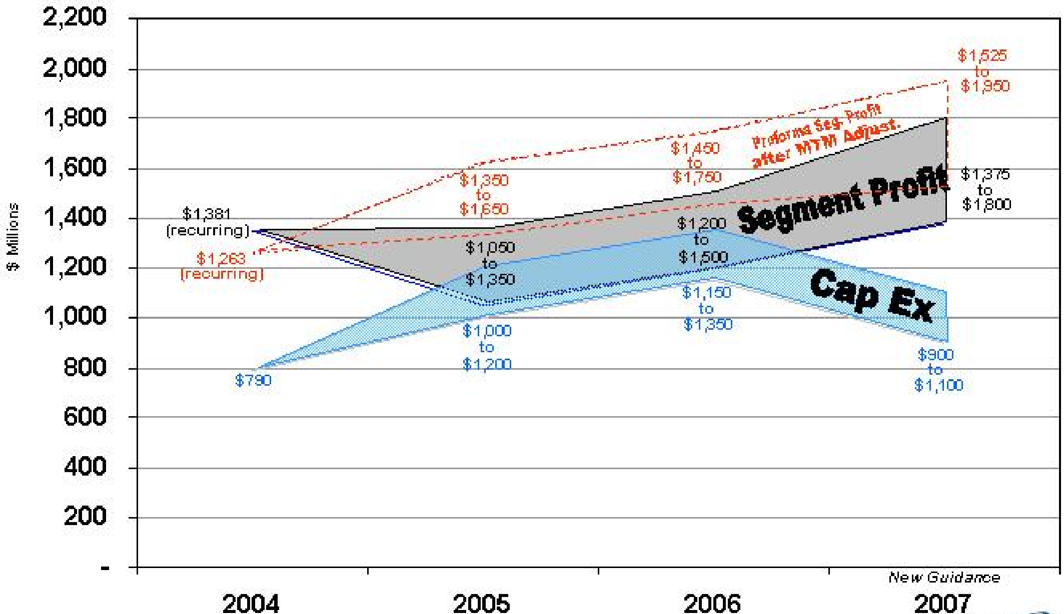
Guidance Trends



* Includes MTM adjustments of ($118) in 2004, $300 in 2005, $250 in 2006, and $150 in 2007

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Financial Strategy/Key Points

- Drive/enable sustainable growth in EVA®/shareholder value
- Maintain a cash/liquidity cushion of $1.0 billion plus
- Continue to steadily improve credit ratios/ratings; ultimately achieving investment grade ratios
- Reduce risk in Power segment
- Increase focus and disciplined EVA® -based investments in natural gas businesses
- Optimize use of free cash flow
- Combination of growth in operating cash flows and reduction in interest costs drives value creation

Summary

Steve Malcolm

Key Points

- Restructuring complete, seeking growth with discipline
- Opportunities are identified
  - Some already in our guidance
  - Need to bring others across the goal line
- Will be executing our game plan
- Measure our success in the upcoming months through updates on our progress

Q&A

Non-GAAP Reconciliations

Non-GAAP Disclaimer

This presentation includes certain financial measures, EBITDA, recurring earnings, free cash flow and recurring segment profit, that are non-GAAP financial measures as defined under the rules of the Securities and Exchange Commission. EBITDA represents the sum of net income (loss), net interest expense, income taxes, depreciation and amortization of intangible assets, less income (loss) from discontinued operations. Recurring earnings and recurring segment profit provide investors meaningful insight into the Company's results from ongoing operations. This presentation is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Management uses these financial measures because they are widely accepted financial indicators used by investors to compare company performance. In addition, management believes that these measures provide investors an enhanced perspective of the operating performance of the Company's assets and the cash that the business is generating. Neither EBITDA nor recurring earnings and recurring segment profit are intended to represent cash flows for the period, nor are they presented as an alternative to net income or cash flow from operations. They should not be considered in isolation or as substitutes for a measure of performance prepared in accordance with United States generally accepted accounting principles.

Certain financial information in this presentation is also shown including Power mark-to-market adjustments. This presentation is accompanied by a reconciliation of these non-GAAP financial measures to their nearest GAAP financial measures. Previously the Company did not qualify for hedge accounting with respect to its Power segment as a result of the Company's stated intent to exit the Power business. The Company ceased efforts to market the sale of Power during the third quarter 2004, and now qualifies for hedge accounting. Hedge accounting reduces earnings volatility associated with Power's portfolio of certain derivative hedging instruments. Prior to the adoption of hedge accounting, these derivative hedging instruments were accounted for on a mark-to-market basis with the change in fair value recognized in earnings each period. Management uses the mark-to-market adjustments to better reflect Power's results on a basis that is more consistent with Power's portfolio cash flows and to aid investor understanding. The adjustments reverse forward unrealized mark-to-market gains or losses from derivatives and add realized gains or losses from derivatives for which mark-to-market income has been previously recognized, with the effect that the resulting adjusted segment profit is presented as if mark-to-market accounting had never been applied to designated hedges or other derivatives. The measure is limited by the fact that it does not reflect potential unrealized future losses or gains on derivative contracts. However, management compensates for this limitation since reported earnings do reflect unrealized gains and losses of derivative contracts. Overall, management believes the mark-to-market adjustments provide an alternative measure that more closely matches realized cash flows for the Power segment.

Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

Non-GAAP Reconciliation Schedule

Reconciliation of Segment Profit (Loss) to Recurring Segment Profit (Loss)
(UNAUDITED)

(Dollars in millions)	2003 1st Qtr [1]	2003 2nd Qtr [1]	2003 3rd Qtr [1]	2003 4th Qtr [1]	2003 Year [1]	2004 1st Qtr [1]	2004 2nd Qtr [1]	2004 3rd Qtr [1]	2004 4th Qtr	2004 Year
Segment profit (loss):										
Power [11]	$ (137.0)	$ 335.9	$ 37.2	$ (101.0)	$ 135.1	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7
Gas Pipeline	150.3	115.5	141.5	148.2	555.5	147.4	132.8	148.8	156.8	585.8
Exploration & Production	113.8	178.7	58.8	50.1	401.4	51.5	43.3	70.1	70.9	235.8
Midstream Gas & Liquids	102.4	(45.1)	76.2	63.8	197.3	110.1	98.5	105.4	235.7	549.7
Other	4.8	(51.7)	4.1	(7.7)	(50.5)	(8.7)	(14.3)	2.4	(21.0)	(41.6)
Total segment profit	$ 234.3	$ 533.3	$ 317.8	$ 153.4	$ 1,238.8	$ 268.3	$ 304.1	$ 436.0	$ 398.0	$ 1,406.4
Nonrecurring adjustments:										
Power	$ (1.9)	$ (246.1)	$ (21.9)	$ 113.4	$ (156.5)	$ -	$ -	$ -	$ -	$ -
Gas Pipeline	-	26.4	-	0.1	26.5	-	9.0	-	-	9.0
Exploration & Production	-	(91.5)	-	-	(91.5)	-	11.3	-	4.1	15.4
Midstream Gas & Liquids	-	92.6	(7.1)	0.2	85.7	-	(16.5)	22.9	(85.0)	(78.6)
Other	-	49.6	(9.2)	-	40.4	6.5	10.8	-	11.8	29.1
Total segment nonrecurring adjust.	$ (1.9)	$ (169.0)	$ (38.2)	$ 113.7	$ (95.4)	$ 6.5	$ 14.6	$ 22.9	$ (69.1)	$ (25.1)
Recurring segment profit (loss):										
Power	$ (138.9)	$ 89.8	$ 15.3	$ 12.4	$ (21.4)	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7
Gas Pipeline	150.3	141.9	141.5	148.3	582.0	147.4	141.8	148.8	156.8	594.8
Exploration & Production	113.8	87.2	58.8	50.1	309.9	51.5	54.6	70.1	75.0	251.2
Midstream Gas & Liquids	102.4	47.5	69.1	64.0	283.0	110.1	82.0	128.3	150.7	471.1
Other	4.8	(2.1)	(5.1)	(7.7)	(10.1)	(2.2)	(3.5)	2.4	(9.2)	(12.5)
Total recurring segment profit	$ 232.4	$ 364.3	$ 279.6	$ 267.1	$ 1,143.4	$ 274.8	$ 318.7	$ 458.9	$ 328.9	$ 1,381.3

Note: Segment profit (loss) includes equity earnings (losses) and income (loss) from investments reported in investing income (loss) in the Consolidated Statement of Operations.
Equity earnings (losses) are from investments accounted for under the equity method. Income (loss) from investments results from the management of investments in certain equity investments.

[1] Amounts have been restated from 3rd Quarter 2004 to reflect Gulf Liquids as continuing operations.

[11] Power's segment profit includes the effect of intra-company interest rate swaps entered into with the corporate parent. We terminated these interest rate derivatives in fourth quarter 2004.

Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

Dollars in millions except for per share amounts

	2004 1Q	2004 2Q	2004 3Q	2004 4Q	2004 Year	2003 1Q	2003 2Q	2003 3Q	2003 4Q	2003 Year
Recurring income from cont. ops available to common shareholders	$ 4	$ 54	$ 136	$ 68	$ 261	$ (53)	$ (18)	$ (2)	$ 58	$ (16)
Recurring diluted earnings per common share	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.48	$ (0.10)	$ (0.03)	$ (0.00)	$ 0.11	$ (0.03)
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(24)	(70)	(188)	(23)	(306)	1	(232)	54	(85)	(262)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186	(17)	45	(45)	25	8
Total MTM adjustments	112	(59)	(143)	(29)	(118)	(15)	(187)	9	(60)	(253)
Tax effect of total MTM adjustments (at 39%)	44	(23)	(56)	(11)	(46)	(6)	(73)	4	(23)	(99)
After tax MTM adjustments	69	(36)	(87)	(17)	(72)	(9)	(114)	5	(37)	(155)
Recurring income from cont. ops available to common shareholders after MTM adjust	$ 73	$ 18	$ 49	$ 51	$ 190	$ (62)	$ (132)	$ 3	$ 22	$ (170)
Recurring diluted earnings per share after MTM adj.	$ 0.14	$ 0.03	$ 0.09	$ 0.09	$ 0.35	$ (0.12)	$ (0.25)	$ 0.01	$ 0.04	$ (0.33)
Weighted average shares - diluted (thousands)	519,485	521,698	529,525	536,497	535,611	517,652	524,546	524,711	518,502	518,137

Note: Recurring income from continuing operations available to common stockholders has been restated to reflect the reclassification of Gulf Liquids to continuing operations.

Adjustments have been made to reverse estimated forward unrealized MTM gains/losses and add estimated realized gains/losses from MTM previously recognized, i.e. assumes MTM accounting had never been applied to designated hedges and other derivatives.

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Non-GAAP Reconciliation

EBITDA Reconciliation

Dollars in millions

	4Q04	2004
Net Income*	**$73**	**$164**
Income from Disc. Operations	22	(71)
Net Interest Expense	170	828
DD&A	173	669
Provision for Income Taxes	88	131
EBITDA*	**$526**	**$1,721**

** Includes gains and impairments on asset sales and prior period adjustments*

Non-GAAP Reconciliation

4Q 2004 Segment Contribution

Dollars in millions

	E&P	Midstream	Gas Pipeline	Power	Corp/Other	Total
Segment Profit (Loss)	$71	$236	$157	($44)	($21)	**$398**
DD&A	51	47	67	5	3	**173**
Segment Profit before DDA	**$122**	**$283**	**$224**	**($39)**	**($18)**	**$571**
General Corporate Expense						**(35)**
Investing Income*						**22**
Other Income						**(33)**
TOTAL						**$526**

** Excluding equity earnings and income (loss) from investments contained in segment profit*

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Non-GAAP Reconciliation

2004 Segment Contribution

Dollars in millions

	E&P	Midstream	Gas Pipeline	Power	Corp/Other	Total
Segment Profit (Loss)	$236	$550	$586	$77	($42)	**$1,406**
DD&A	192	178	264	20	15	**669**
Segment Profit before DDA	**$428**	**$728**	**$850**	**$97**	**($27)**	**$2,075**
General Corporate Expense						**(120)**
Investing Income*						**34**
Other Income						**(269)**
TOTAL						**$1,721**

** Excluding equity earnings and income (loss) from investments contained in segment profit*

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2005 Forecast EBITDA Reconciliation

Dollars in millions

	2005
Net Income	**$175 – 325**
Income from Disc. Operations	5 – (5)
Net Interest	625 – 660
DD&A	700 – 775
Prov. (Benefit) for Income Taxes	155 – 245
Other/Rounding	(10) – 0
EBITDA – Reported & Recurring	**$1,650 – 2,000**
MTM Adjustments	300
EBITDA after MTM Adj.	**$1,950 – 2,300**

Non-GAAP Reconciliation

2005 Forecast Segment Contribution

	E&P	Midstream	Gas Pipeline	Power	Corp/ Other	Total
Segment Profit (Loss)	400 - 475	350 - 430	545 - 585	(250)-(150)	5 – 10	1,050 - 1,350
DD&A	220 - 250	180 - 190	280 - 290	10 - 20	10 - 25	700 - 775
Segment Profit before DDA	620 - 725	530 - 620	825 - 875	(240)–(130)	15 – 35	1,750 - 2,125
Other (Primarily General Corporate Expense & Investing Income)						(100) - (125)
TOTAL RECURRING						1,650 - 2,000

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Non-GAAP Reconciliation

2005 Forecast Guidance Reconciliation

Dollars in millions, except per-share amounts

	2005
Net Income	**$175 – 325**
Less: Discontinued Operations	5 – (5)
Income from Continuing Ops	**$180 – $320**
Recurring Income from Cont. Ops	**$180 – $320**
Recurring EPS	**$0.31 - $0.56**
Mark-to-Market Adjustment (Pretax)	300
Less Taxes @ 39%	(117)
Mark-to-Market Adjust. After Tax	183
Income from Cont. Ops after MTM Adj.	**$363 – $503**
Income from Cont. Ops after MTM Adj. EPS	**$0.63 - $0.88**

Appendix

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2004 Effective Tax Rates

Dollars in millions	Combined		Continuing Ops.		Disc. Ops.	
Fourth Quarter 2004						
Federal	$64	35%	$64	35%	$0	0%
State	17	9%	16	9%	1	500%
Foreign	19	10%	(2)	(1%)	21	10500%
Other	10	5%	10	5%	0	0%
Tax Provision	**$110**	**46%**	**$88**	**48%**	**22**	**11000%**
Total Year 2004						
Federal	$107	35%	$79	35%	$28	35%
State	32	11%	28	12%	4	5%
Foreign	(17)	(6%)	6	3%	(23)	(29%)
Other	18	6%	18	8%	0	0%
Tax Provision	**$140**	**46%**	**$131**	**58%**	**9**	**11%**

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Exploration & Production

4Q 2004 Net Realized Price Calculation

	Unhedged	4Q '04 Hedge
Market Price:		
NYMEX	$6.70 - $7.60	$4.05
Basis Differential	(1.00 - 1.65)	(0.50)
Net basin market price	**$5.70 - $5.95**	**$3.55**
Fuel & Shrinkage/Gathering/ Transportation	(0.80 - 1.00)	(0.80 - 1.00)
Net Price	**$4.70 - $5.15**	**$2.55 - $2.75**
Quarter Volume Totals	(qtr volumes) x (% unhedged)	(qtr volumes) x (% hedged)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

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Exploration & Production

2005 Price Modeling

	Unhedged	2005 Hedge
Market Price:		
NYMEX	$6.00 - $6.60	$4.44
Basis Differential	(0.50 - 0.70)	(0.47)
Net basin market price	**$5.50 - $5.90**	**$3.97**
Fuel & Shrinkage/Gathering/ Transportation	(0.80 - 1.00)	(0.80 - 1.00)
Net Price	**$4.70 - $5.15**	**$2.97 - $3.17**
Year Volume Totals (Bcfe)	(total daily vols - daily hedge vols) x (365/1000)	(daily hedge volumes) x (365/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

	2005	2006	2007
Unhedged Price (NYMEX)	$6.34	$5.96	$5.75

Note:
- Economic impact of hedges may be different from the volume hedged due primarily to fuel and shrink and direct taxes

Williams

Enterprise Risk Management

Dollars in millions	E&P	Midstream	Power	Corp./ Other	Total	12/31/03 Total
	As of 12/30/04					
Margins & Ad. Assur.	$50	$10	$74	-	$134	$527
Prepayments [1]	-	2	38	-	40	81
Subtotal	**$50**	**$12**	**$112**	**$ -**	**$174**	**$608**
Letters of Credit	399	123	238	95	894	378
Total as of 12/30/04	**$449**	**$135**	**$350**	**$95**	**$1,068**	**$986**
Total as of 9/30/04	**$448**	**$191**	**$369**	**$114**	**$1,122**	
Change	**$1**	**($56)**	**($19)**	**($19)**	**($54)**	

[1]December 31, 2003 values include certain reclassifications to conform with current presentation.

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Enterprise Risk Management

Dollars in millions

- Margin volatility (99% confidence interval)
  - Incremental liquidity requirement

	12/30/04	9/30/04
– 30 days	($106)	($118)
– 180 days	($268)	($234)
– 360 days	($353)	($336)

Assumption: The margin numbers above consist of only the forward marginable position values, starting from February 2005.

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Enterprise Risk Management

Estimated dollars in millions

Sensitivities Analysis

	WMB[1] Natural Gas (Per MMBtu)	Power[2] West Spark Spread Power Price (Per MWh)	Midstream[3] Processing Margin NGL Price (Per Gallon)
Price Increase	**$0.10**	**$5.00**	**$0.01**
2005	($5)-(2)	$5-10	$10-15
2006	$2-5	$5-15	$10-15
2007	$7-10	$5-15	$10-15

1 *Assumes a correlated movement in prices across all commodities, including spreads, for all Williams business units combined.*

2 *Assumes a non-correlated change in West power prices only, no change in power volatility, full extrinsic value not included. Heat rate and position change associated with Spark Spread increase is consistent across all months. Cash flow ranges are not linear.*

3 *Assumes a non-correlated change in NGL processing spread (i.e. change in NGL price only).*

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Power

Estimated Total Cash Flows

Undiscounted dollars in millions

Combined Power Portfolio *Estimated as of 12/31/04*	**2004**	**2005 F**	**2006 F**	**2007 F**
Tolling Demand Payment Obligations	($397)	($395)	($399)	($404)
Resale of Tolling	144	115	99	88
Full Requirements	12	29	13	6
Long-term Physical Forward Power Sales	72	71	48	51
OTC Hedges	170	75	143	25
Estimated Hedged Tolling Revenues	140	216	270	265
Subtotal	$141	$111	$174	$31
Estimated Merchant Cash Flows	0	67	53	164
Est. Combined Power Portfolio Cash Flows	$141	$178	$227	$195
SG&A and Other	(79)	(67)	(65)	(66)
Subtotal	$62	$111	$162	$129
Working Capital and Other	503	(18)	(27)	(37)
Estimated Cash Flows After SG&A	$565	$93	$135	$92

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.

Note: 2004 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

Power

West – Estimated Total Cash Flows

Undiscounted dollars in millions

West Power Portfolio *Estimated as of 12/31/04*	**2004**	**2005 F**	**2006 F**	**2007 F**
Tolling Demand Payment Obligations	($154)	($155)	($155)	($157)
Resale of Tolling	144	115	99	88
Long-term Physical Forward Power Sales	89	69	48	51
OTC Hedges	98	57	102	22
Est. Tolling Cash Flows Associated With Hedge	103	141	172	182
Subtotal	$280	$227	$266	$186
Estimated Merchant Cash Flows	0	34	24	85
Estimated Cash Flows	$280	$261	$290	$271

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.

Note: 2004 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

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Power

Central – Estimated Total Cash Flows

Undiscounted dollars in millions

Mid-Continent Power Portfolio *Estimated as of 12/31/04*	**2004**	**2005 F**	**2006F**	**2007 F**
Tolling Demand Payment Obligations	($87)	($87)	($88)	($89)
Long-term Physical Forward Power Sales	(17)	2	0	0
OTC Hedges	35	(15)	(11)	(9)
Est. Tolling Cash Flows Associated With Hedge	2	26	23	18
Subtotal	($67)	($74)	($76)	($80)
Estimated Merchant Cash Flows	0	10	18	35
Estimated Cash Flows	($67)	($64)	($58)	($45)

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.

Note: 2004 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

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Power

East – Estimated Total Cash Flows

Undiscounted dollars in millions

East Power Portfolio *Estimated as of 12/31/04*	**2004 A**	**2005 F**	**2006 F**	**2007 F**
Tolling Demand Payment Obligations	($156)	($153)	($156)	($158)
Full Requirements	12	29	13	6
OTC Hedges	37	33	52	12
Est. Tolling Cash Flows Associated With Hedge	35	49	75	65
Subtotal	($72)	($42)	($16)	($75)
Estimated Merchant Cash Flows	0	23	11	44
Estimated Cash Flows	($72)	($19)	($5)	($31)

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.

Note: 2004 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

Williams

NewsRelease

NYSE: WMB

Date: Feb. 23, 2005

Williams Replaces 248 Percent of 2004 U.S. Natural Gas Production
Total Domestic and International Proved Reserves Grow to 3.2 Tcfe

TULSA, Okla. – Williams (NYSE:WMB) announced today that its domestic and international proved natural gas and oil reserves as of Dec. 31, 2004, increased to 3.2 trillion cubic feet equivalent (Tcfe).

Williams replaced its 2004 U.S. natural gas production of 191 billion cubic feet equivalent (Bcfe) at a ratio of 248 percent. A reserves reconciliation follows the main text in this news release.

U.S. reserves increased 10.5 percent to 3.0 Tcfe compared with 2.7 Tcfe a year earlier. More than 99 percent of Williams' U.S. proved reserves are natural gas.

Key to Williams' U.S. reserves increases were drilling and downspacing in the Piceance Basin along with drilling in the Powder River and San Juan basins. Williams also achieved a domestic drilling success rate of approximately 99 percent in 2004.

International reserves were unchanged at 36 million barrels of oil equivalent – 68 percent of which is crude and liquids and 32 percent natural gas.

"Our significant acceleration of drilling activity drove another year of strong reserves growth," said Ralph Hill, senior vice president of Williams' exploration and production business.

"Our 2004 drilling activity resulted in the addition of 451 billion cubic feet equivalent in net reserves. That exceeds what was strong performance in 2003, when we added 408 billion cubic feet equivalent in net reserves as a result of drilling activity."

In 2005, Williams plans to increase capital spending by approximately 25 percent over 2004 levels. The company plans to invest between $500 million and $575 million to develop production from its long-term drilling inventory.

"We're optimistic about our potential to quickly develop our asset base of long-lived, repeatable reserves," Hill said. "The experience and expertise we've established in our core basins makes us an operator of choice and enhances our ability to capture existing and new opportunities for reserves additions."

Williams' exploration and production business primarily develops natural gas reserves in the Piceance, Powder River, San Juan and Arkoma basins in the United States.

Williams also owns an approximately 69 percent interest in APCO Argentina (NASD:APAGF), a separately traded oil and gas company with properties in Argentina, and a 10 percent interest in the La Concepcion oil field in Venezuela.

Virtually all – 99.6 percent – of Williams' year-end 2004 U.S. proved reserves estimates were either audited by Netherland, Sewell & Associates, Inc., or, in the case of reserves estimates related to properties underlying the Williams Coal Seam Gas Royalty Trust (NYSE:WTU), were prepared by Miller and Lents, LTD.

Proved reserves estimates for APCO Argentina were prepared by Ryder Scott Company. Gaffney, Cline & Associates audited La Concepcion's proved reserves estimates .

The reserve replacement ratio of 248 percent was calculated by dividing the sum of changes (acquisitions, additions and revisions) to the estimated proved reserves during 2004 by Williams' 2004 production of 191 Bcfe.

For purposes of converting volumes of crude oil and liquids reserves to a natural-gas-equivalent measure in this report, the company used a ratio of one barrel to 6,000 cubic feet.

Proved reserves are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under assumed economic conditions.

U.S. Proved Reserves Reconciliation
Figures in billion cubic feet equivalent of natural gas

Proved reserves Dec. 31, 2003	2,703
Acquisitions, net of divestitures	23
Additions and revisions	451
Production	(191)
Proved reserves Dec. 31, 2004	2,986

About Williams (NYSE:WMB)
Williams, through its subsidiaries, primarily finds, produces, gathers, processes and transports natural gas. The company also manages a wholesale power business. Williams' operations are concentrated in the Pacific Northwest, Rocky Mountains, Gulf Coast, Southern California and Eastern Seaboard. More information is available at www.williams.com.

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