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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): November 3, 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 November 3, 2005, The Williams Companies, Inc. ("Williams" or the "Company") issued a press release announcing its financial results for the quarter ended September 30, 2005. A copy of the press release and its accompanying 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 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 7.01. Regulation FD Disclosure.

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 November 3, 2005.

The slide presentation is being furnished pursuant to Item 7.01, Regulation FD Disclosure. 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 November 3, 2005, publicly announcing its third quarter 2005 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the November 3, 2005, public conference call and webcast.

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: November 3, 2005

/s/ Donald R. Chappel

Name: Donald R. Chappel

Title: Senior Vice President and Chief Financial Officer

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
Exhibit 99.1	Copy of Williams’ press release dated November 3, 2005, publicly announcing its third quarter 2005 financial results.
Exhibit 99.2	Copy of Williams’ slide presentation to be utilized during the November 3, 2005, public conference call and webcast.

NewsRelease

NYSE: WMB

Date: Nov. 3, 2005

Williams Reports Third-Quarter 2005 Financial Results

- *Natural Gas Production Climbs 19% During First 9 Months*
- *Net Cash from Operations Exceeds $1 Billion Through First Three Quarters*
- *Third-Quarter Results Lowered by Effect of Mark-to-Market Losses*
- *Guidance Raised for 2005, 2006 and 2007 on Higher Natural Gas Prices*
- *Company Plans Sale of Certain Interests to Williams Partners L.P.*
- *2006 Capital Spending Increased by $300 Million for E&P and Midstream*

3Q Summary Financial Information

	3Q 2005		3Q 2004	
	millions	per share	millions	per share
Income from continuing operations	$ 5.7	$ 0.01	$ 16.2	$ 0.03
Income (loss) from discontinued operations	($1.3)	$ 0.00	$ 82.4	$ 0.16
Net income	$ 4.4	$ 0.01	$ 98.6	$ 0.19
Recurring income (loss) from continuing operations*	($ 4.6)	$ (0.01)	$ 135.8	$ 0.26
After-tax mark-to-market adjustments	$ 129.9	$ 0.23	($ 86.8)	($ 0.17)
Recurring income from continuing operations - after mark-to-market adjustment*	$ 125.3	$ 0.22	$ 49.0	$ 0.09

Year-to-Date Summary Financial Information

	YTD 2005		YTD 2004	
	millions	per share	millions	per share
Income (loss) from continuing operations	$ 248.6	$ 0.42	($ 2.3)	($ 0.01)
Income (loss) from discontinued operations	($ 1.8)	$ 0.00	$ 92.6	$ 0.18
Net income	$ 246.8	$ 0.42	$ 90.3	$ 0.17
Recurring income from continuing operations*	$ 259.7	$ 0.44	$ 193.5	$ 0.37
After-tax mark-to-market adjustments	$ 97.6	$ 0.16	($ 54.2)	($ 0.10)
Recurring income from continuing operations - - after mark-to-market adjustment*	$ 357.3	$ 0.60	$ 139.3	$ 0.27

* A schedule reconciling income (loss) from continuing operations to recurring income (loss) from continuing operations and mark-to-market adjustments (non-GAAP measures) is available on Williams' Web site at www.williams.com and as an attachment to this press release.

TULSA, Okla. – Williams (NYSE:WMB) today announced third-quarter 2005 unaudited net income of $4.4 million, or 1 cent per share on a diluted basis, compared with net income of $98.6 million, or 19 cents per share, for third-quarter 2004.

Year-to-date through Sept. 30, Williams reported net income of $246.8 million, or 42 cents per share on a diluted basis, compared with net income of $90.3 million, or 17 cents per share, for the first three quarters of 2004.

For third-quarter 2005, the company reported income from continuing operations of $5.7 million, or 1 cent per share on a diluted basis, compared with $16.2 million, or 3 cents per share, for third-quarter 2004 on a restated basis.

Results for the 2005 quarter reflect the benefit of increased natural gas production and higher net realized average prices for production sold, along with reduced levels of interest expense. These benefits were offset by the impact of forward unrealized mark-to-market losses experienced in the Power segment. Results for the 2004 quarter reflect the benefit of forward unrealized mark-to-market gains experienced in Power, offset by approximately $155 million in pre-tax charges associated with the early retirement of debt.

Rising natural gas prices during the third quarter of this year benefited Williams' Exploration & Production business, but contributed to reduced results in the company's Power business.

For the first nine months of 2005, Williams reported income from continuing operations of $248.6 million, or 42 cents per share on a diluted basis, compared with a loss of $2.3 million, or a loss of 1 cent per share, for the same period in 2004 on a restated basis.

CEO Perspective

"The benefit of having diversity in our businesses and our revenue streams was evident during the third quarter," said Steve Malcolm, chairman, president and chief executive officer.

"We were able to create value and produce positive results, despite dealing with the hurricanes and a variety of factors that strained results in our Power business.

"At the same time, our cash flows remain strong, we're raising our guidance and we've increased our capital spending estimate for 2006.

"We're making these investments to produce the natural gas that America needs, to provide reliable services to our customers, and to seize opportunities to help bring even more energy online by building new pipeline and processing systems," Malcolm added.

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

To provide an added level of disclosure and transparency, Williams continues to provide an analysis of recurring earnings adjusted for all mark-to-market effects from its Power business unit. Recurring earnings exclude items of income or loss that the company characterizes as unrepresentative of its ongoing operations.

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 $125.3 million, or 22 cents per share, for the third quarter of 2005. In last year's third quarter, the adjusted recurring income from continuing operations was $49.0 million, or 9 cents per share, on a restated basis.

Results for the 2005 quarter reflect the benefit of increased natural gas production and higher net realized average prices for production sold, along with reduced levels of interest expense.

For the first nine months of 2005, 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 $357.3 million, or 60 cents per share, compared with $139.3 million, or 27 cents per share, for the same period in 2004 on a restated basis.

A reconciliation of the company's income from continuing operations to recurring income from continuing operations and mark-to-market adjustments accompanies this news release.

Business Segment Performance

Williams' primary businesses – Exploration & Production, Midstream Gas & Liquids, Gas Pipeline and Power – reported combined segment profit of $214.6 million in the third quarter of 2005.

In the third quarter a year ago, these businesses reported combined segment profit of $433.6 million on a restated basis.

For the first nine months of 2005, the four major businesses reported combined segment profit of $1.05 billion compared with $1.03 billion for the same period last year on a restated basis.

Results for 2005 have benefited primarily from increased natural gas production volumes and higher net realized average prices, and steady, expected performance in Gas Pipeline. Results for 2005 have been negatively affected by the level of forward unrealized mark-to-market losses during the third quarter.

Exploration & Production: Volumes Up 19 Percent for First Nine Months of 2005

Exploration & Production, which includes natural gas production and development in the U.S. Rocky Mountains, San Juan Basin and Mid-continent, and oil and gas development in South America, reported third-quarter 2005 segment profit of $158.8 million.

In the third quarter a year ago, the business reported segment profit of $70.1 million. The improvement for the 2005 quarter reflects the benefit of significant increases in both production volumes and net realized average prices for production sold, along with a $21.7 million gain on the sale of certain outside-operated properties. These benefits were partially offset by higher expenses and a $15.8 million loss due to hedge ineffectiveness for future periods associated with the company's NYMEX collars.

For the first nine months of 2005, Exploration & Production reported segment profit of $380.8 million, compared with $164.9 million for the same period last year. The increase is primarily a result of the same production and pricing factors listed above.

Year-to-date through Sept. 30, average daily production from domestic and international interests was approximately 649 million cubic feet of gas equivalent (MMcfe), compared with 546 MMcfe for the same period in 2004 – an increase of approximately 19 percent.

Average daily domestic production volumes for the third quarter of 2005 totaled 629 MMcfe. That was approximately 18 percent higher than domestic volumes of 535 MMcfe from the same quarter a year ago. Increased production continues to primarily reflect higher volumes in the Piceance Basin. Williams also is realizing favorable production growth from the Big George area in the Powder River Basin.

Year-over-year, the business has benefited from higher domestic production prices, offset somewhat by higher expenses. In addition, average sales prices in 2005 reflect a lower share of volumes that are hedged and increased contracted prices on the volumes that are hedged. During the third quarter of 2005, Williams realized net domestic average prices of $4.80 per Mcfe compared with $3.34 per Mcfe in the third quarter a year ago – an increase of approximately 44 percent.

Williams currently has 15 rigs operating in the Piceance Basin of western Colorado – its cornerstone property for production growth. Williams also is preparing to deploy a new rig from Helmerich & Payne in the Piceance later this month or in early December. The original delivery schedule has been impacted by approximately one month due to disruptions caused by Hurricane Rita at a fabrication facility. A total of 10 new rigs are scheduled for delivery in the Piceance during 2005 and 2006. Williams has each of the new rigs under contract for a term of three years.

Williams now plans to spend between $675 million to $725 million in its Exploration & Production business in 2005, compared with previous guidance of $605 million to $680 million. The change is primarily due to increased activity for new opportunities in the Piceance Basin, accelerated drilling in the Powder River Basin and increased drilling costs.

Williams also has increased its expectation for segment profit from Exploration & Production in 2005. The company now expects $575 million to $600 million in segment profit, which includes $29 million of non-recurring income and the negative impact of the $15.8 million loss due to hedge ineffectiveness. That expectation is up from previous guidance of $410 million to $485 million for that measure. The increase is primarily the result of higher realized prices during the third quarter and expected prices during the fourth quarter.

Midstream Gas & Liquids: Seizes Growth Opportunities in West, Deepwater Gulf

Midstream, which provides natural gas gathering and processing services, along with natural gas liquids (NGL) fractionation and storage services and olefins production, reported third-quarter 2005 segment profit of $121.1 million.

In the third quarter a year ago, the business reported segment profit of $105.4 million on a restated basis. The quarterly improvement primarily reflects increased gathering and processing fee income; higher natural gas liquids production margins realized in the West; and the absence of a $16.5 million unfavorable adjustment to revenues recorded in third-quarter 2004. These benefits were offset partially by lower revenues associated with natural gas gathering and processing facilities that were affected by production shut-ins caused by hurricanes Katrina and Rita. More information about these events is contained later in the news release.

For the first nine months of 2005, Midstream reported segment profit of $358.8 million compared with a restated $314 million for the same period last year.

Through Sept. 30, Midstream had sold 1.01 billion gallons of NGL equity volumes compared with equity sales of 1.03 billion gallons for the first three quarters of 2004. Third-quarter 2005 performance was negatively affected by hurricanes Katrina and Rita. These equity volumes are retained and subsequently marketed by Williams as payment-in-kind under the terms of certain processing contracts.

Gathering and processing volumes increased modestly year-over-year despite the effects of hurricanes Katrina and Rita during the third quarter. Gathering volumes were 949.4 trillion British thermal units (TBtu) in the first three quarters of 2005, compared with 931.4 TBtu in the 2004 period. Fee processing volumes in the first three quarters of 2005 were 555.8 TBtu compared with 555.2 TBtu in the first nine months of 2004.

Williams' financial results for Midstream have benefited from favorable natural gas liquids (NGL) margins in both 2005 and 2004, particularly in its western U.S. natural gas processing operations in areas such as Opal and Wamsutter in Wyoming.

Citing the increased demand for processing capacity, Williams today announced plans to expand its Opal, Wyo., facility by adding a fifth cryogenic processing train. The project is designed to boost the overall processing capacity of Williams' Opal facility from more than 1.1 billion cubic feet per day to approximately 1.45 billion cubic feet per day, with the ability to recover approximately 68,000 barrels per day of NGL products. Work on the project is scheduled to be completed in second-quarter 2007.

Subsequent to the close of the third quarter, Williams also announced a $177 million offshore expansion to gather oil and gas from the Blind Faith Field in the deepwater Gulf of Mexico. To accommodate this anticipated production, Williams has agreed to extend its Canyon Chief and Mountaineer pipelines by 37 miles each. The project is scheduled for completion in third-quarter 2007.

During the third quarter, Williams Partners L.P. (NYSE:WPZ) completed its initial public offering. The Williams Companies, Inc. (NYSE:WMB) and certain of its affiliates own approximately 60 percent of the new master limited partnership that primarily gathers, transports and processes natural gas and fractionates and stores natural gas liquids.

In addition to Williams Partners' initial asset portfolio, Williams now proposes to sell an approximate 25 percent interest in its existing gathering and processing assets in the Four Corners area to the master limited partnership.

On a 100 percent basis, the unaudited operating income plus depreciation from the Four Corners assets has been $154 million, $151 million and $165 million for 2002, 2003 and 2004 respectively. The same measure for the first nine months of 2005 is $136 million.

The terms of this proposed transaction, including price, will be subject to approval by the boards of directors of both Williams and Williams Partners' general partner. Assuming such approvals are obtained, it is expected that the transaction would be completed during the second quarter of 2006.

Williams continues to plan to spend $120 million to $140 million on capital expenditures in its Midstream business in 2005.

Williams has increased its expectation for segment profit from Midstream in 2005. The company now expects $440 million to $480 million in segment profit from Midstream. That expectation is changed from previous guidance of $400 million to $470 million for that measure. The increase is primarily the result of favorable liquids margins.

Gas Pipeline: Expansions Tied to Market Demand

Gas Pipeline, which primarily delivers natural gas to markets along the Eastern Seaboard, in Florida and in the Northwest, reported third-quarter 2005 segment profit of $161.1 million. In the third quarter a year ago, the business reported segment profit of $148.8 million.

The increase in third-quarter 2005 segment profit compared with a year ago is primarily attributable to the benefit of a $14.2 million favorable adjustment from the resolution of litigation associated with its fuel tracker filings and an increase in equity earnings from Gulfstream Natural Gas System, L.L.C., a joint venture in which Williams owns a 50 percent interest. These items were partially offset by the termination of a firm transportation agreement related to the Gray's Harbor lateral on the Northwest system effective January 2005.

For the first nine months of 2005, Gas Pipeline reported segment profit of $493 million compared with $429 million for the same period last year. The increase for the nine-month period in 2005 is primarily the result of the previously noted litigation adjustment; the benefit of a second-quarter pension expense correction of $17 million; approximately $13 million in liability reductions associated with prior periods; $16 million in higher equity earnings from its Gulfstream investment; and the absence of a $9 million write-off of capitalized costs in 2004. These were partially offset by the termination of the previously mentioned Gray's Harbor agreement.

Following the close of the third quarter, Transco completed construction of a $16 million project to add 105,000 dekatherms per day of new firm service in central New Jersey. This expansion was placed into service Nov. 1.

Transco also completed a successful open season in the third quarter for new capacity into the greater Washington, D.C., area. Customers executed precedent agreements for a total of 165,000 Dth/d of firm transportation service from receipt points in Guilford and Rockingham counties in North Carolina to certain mainline delivery points in northern Virginia and Maryland. The project, which is subject to Federal Energy Regulatory Commission approval, is anticipated to be placed into service in November 2007.

Within the past week, Transco and Northwest Pipeline also announced new open seasons to provide between 200,000 and 300,000 Dth/d of additional capacity in the Northeast and approximately 575,000 Dth/d of additional capacity in Colorado, respectively.

In Washington state, Williams has received final approval from the FERC to construct and operate approximately 80 miles of 36-inch pipeline loop in the existing Northwest Pipeline right of way between Sumas and Washougal, Wash. The estimated $333 million project will replace most of the capacity served previously by 268 miles of an existing 26-inch pipeline. Most of the construction is scheduled to occur in 2006 with an in-service date of November 2006.

In August, Gulfstream began providing transportation service to Tampa Electric under a new long-term firm service agreement. The new contract provides up to 48,000 Dth/d to serve the H.L. Culbreath Bayside power generation facility in Hillsborough County, Fla.

In October, Gulfstream completed a debt offering, issuing $850 million of senior unsecured notes of various maturities to certain institutional investors via a 144A private placement. Gulfstream used the proceeds to repay an existing construction loan and to return capital to its equity owners, including approximately $310 million to Williams.

Williams is raising the low end of its 2005 capital spending range for Gas Pipeline by $20 million to reflect higher activity through the third quarter. The company now plans to spend $390 million to $420 million in capital expenditures for Gas Pipeline this year.

Williams also is increasing its expectation for 2005 segment profit from Gas Pipeline. The company now expects $630 million to $645 million in segment profit from this business, which includes $50 million of non-recurring items and adjustments related to prior periods. Williams previously expected $590 million to $615 million in segment profit for 2005. The increase is primarily the result of the $14 million non-recurring item recorded in the third quarter, as well as lower than anticipated expenses in the last half of the year.

Power: Continues Cash-Flow Positive Year-to-Date

Power manages an approximately 7,000-megawatt power portfolio and provides services that support Williams' natural gas businesses.

3Q Power Recurring Segment Profit Adjusted for Mark-to-Market Impact

	3Q '05 (millions)	3Q '04 (millions)
Recurring Segment profit (loss)	($ 226.0)	$ 109.3
Mark-to-market adjustments — net	213.0	(142.2)
Recurring segment loss after mark-to-market adjustments	($ 13.0)	($ 32.9)

YTD Power Recurring Segment Profit Adjusted for Mark-to-Market Impact

	YTD '05 (millions)	YTD '04 (millions)
Recurring Segment profit (loss)	($ 162.4)	$ 121.1
Mark-to-market adjustments — net	160.1	(87.1)
Recurring segment loss after mark-to-market adjustments	($ 2.3)	$ 34.0

Power reported a third-quarter 2005 segment loss of $226.4 million, significantly reduced from a segment profit for the same quarter a year ago of $109.3 million. The reduction is primarily the result of unfavorable year-over-year changes from forward unrealized mark-to-market results. The changes consist of $141.1 million in forward unrealized mark-to-market losses in third-quarter 2005 versus $187.9 million in forward unrealized mark-to-market gains in third-quarter 2004. The mark-to-market gains in the third quarter of 2004 resulted primarily from gas price increases on net long gas contracts that did not qualify for hedge accounting. The mark-to-market losses in third-quarter 2005 resulted from gas price increases on net short gas contracts that do not qualify for hedge accounting.

Due to the adoption of hedge accounting in fourth-quarter 2004 and the related designation of certain derivative contracts as hedges, there was a significant change in the pool of contracts that are subject to changes in fair value being recognized as mark-to-market income in the current period.

In recognition of its stated business intent, Power seeks to reduce its economic risk by selling power forward and by buying needed gas forward to maintain a balanced position. During third-quarter 2005 as new power sales/hedges were being completed, and in the normal course of business to reduce risk, Power began reducing certain less effective hedges by entering into offsetting economic contracts. Some of these offsetting contracts did not qualify for hedge accounting and the related changes in fair value were recorded as mark-to-market losses in the current period. Net unrealized gains of $379 million related to the effective portion of Power's hedges are reported in accumulated other comprehensive loss in third-quarter 2005.

Power reported a recurring segment loss adjusted for the effect of mark-to-market accounting of $13.0 million in third-quarter 2005, compared with a loss of $32.9 million a year ago. The year-over-year improvement primarily reflects the absence of losses from the interest rate and crude and refined products portfolio, offset by the effects of milder weather in California, an unplanned outage at the Ironwood facility and the impact of Hurricane Katrina.

For the first nine months of 2005, Power reported a segment loss of $187.3 million compared with segment profit of $121.1 million for the same period in 2004. That change is primarily the result of $179 million in lower forward unrealized mark-to-market gains this year, the impact of milder weather in California, lower spark spreads due to higher natural gas prices, the losses from Hurricane Katrina, the outage at the Ironwood facility and $12 million in higher expenses related to settlements and litigation contingencies.

For the first nine months of 2005, Power reported a recurring segment loss of $2.3 million adjusted for the effect of mark-to-market accounting, compared with segment profit of $34.0 million for the same period in 2004.

The year-over-year decline is primarily due to milder weather in California, losses from Hurricane Katrina, the outage at the Ironwood facility in the third quarter, and the absence of a legacy natural gas portfolio that liquidated in first-quarter 2004, offset by the absence of losses in the interest rate portfolio, which was liquidated in fourth-quarter 2004, and the absence of losses in the crude and refined products portfolio.

During and subsequent to this year's third quarter, Power completed four new power sales contracts, ranging in term and volume, through 2010. These new contracts effectively reduce risk, increase value and increase cash-flow certainty. Additionally, these power sales reduce the portfolio's future exposures to fuel-price and weather volatility.

In the third quarter of 2005, Power used approximately $41 million in cash flow from operations, largely the result of the above referenced portfolio losses and working capital changes. For the first nine months of 2005, Power generated approximately $44 million in cash flow from operations, largely the result of changes in working capital.

As a result of the unexpectedly mild weather in California and the other factors already listed, the company has changed its 2005 expectation for cash flow from operations in Power to $25 million to $75 million on a basis that excludes future changes in working capital used in commodity risk management activity on behalf of all of Williams' commodity businesses. Williams previously expected to generate cash flow from operations of $50 million to $150 million in 2005.

As a result of the large mark-to-market losses recorded in the third quarter, coupled with the effects of higher natural gas prices and milder summer weather in California, Williams now expects a revised segment loss of between $175 million to $225 million from Power on a basis that excludes future mark-to-market changes. Williams previously expected a segment profit range of a $50 million loss to a $50 million profit.

On a basis adjusted for the effects of mark-to-market accounting, Williams also has revised its expectation for Power's 2005 recurring earnings to range from a loss of $50 million to break even due to the mild weather and other factors previously mentioned. Williams previously expected Power to generate 2005 recurring earnings of $50 million to $150 million on a basis adjusted for the effects of mark-to-market accounting.

Cash, Liquidity and Debt: New Credit Facilities Provide Additional Liquidity

For the year through Sept. 30, net cash provided by operating activities was $1.08 billion, compared with $1.09 billion for the same period in 2004. The company has increased its expectation for cash flow in 2005 to $1.325 billion to $1.525 billion. The company previously expected $1.15 billion to $1.45 billion for the year.

At the end of the third quarter, Williams had total liquidity of more than $2 billion. This consists of unrestricted cash and cash equivalents of approximately $1.4 billion, other liquid investments of $86 million, and $768 million in unused and available revolving credit facilities.

In September, the company obtained $700 million in two five-year unsecured credit facilities. Williams now has a total of $2.475 billion in credit facilities.

For the first three quarters of 2005, Williams has realized a year-over-year decrease in interest expense of $167.6 million as a result of debt reductions. At Sept. 30, 2005, Williams' total outstanding long-term debt was approximately $7.7 billion.

Gulf Coast Update: Hurricane Rita Hits Close to Home for Operations, Employees

Williams shut-in the majority of its onshore and offshore gathering and processing assets in the Gulf as a precaution in advance of hurricanes Katrina and Rita.

The Transco and Gulfstream natural gas pipeline systems remained operational throughout both hurricanes and continued to meet market demand, although volumes were reduced on both systems because of producers' storm-related supply shut-ins.

Williams' operations were relatively unscathed by the first hurricane, but the eye of the second hurricane came through the vicinity of Cameron, La., and Johnsons Bayou where Williams operates the Cameron Meadows natural gas processing plant and a Transco compression and metering station. Both facilities were damaged by the storm and more than half of the company's 34 employees in the area lost their homes.

Repairs are essentially complete at the Transco compressor station. The facility returned to service at a limited capacity Nov. 1. The station is flowing and dehydrating natural gas.

The Cameron Meadows processing plant sustained significant damage and is expected to remain out of service for an extended period. Williams is evaluating the extent, nature, projected cost and feasibility of repairs at the Cameron Meadows plant. The company also is considering other options for restoring processing services in 2006 for the customers that have been served by the facility. The plant is covered by standard property and business interruption insurance.

Offshore, the Devils Tower deepwater spar at Mississippi Canyon block 773 is preparing to resume commercial operations. Startup is expected to occur today or within the next few days. The facility has been available for service since shortly after Hurricane Katrina, but production had been shut-in until a downstream third-party oil terminal near Venice, La., reopened for business.

Guidance: Company Raises Profit Targets and Capital Spending

In 2005, Williams now expects consolidated segment profit of $1.375 billion to $1.525 billion, compared with previous expectations of $1.3 billion to $1.585 billion for this measure.

On a recurring basis adjusted for the impact of mark-to-market accounting, Williams now expects $1.55 billion to $1.70 billion in consolidated segment profit and earnings per share of 84 cents to 94 cents for 2005. The company previously expected $1.375 billion to $1.660 billion in consolidated segment profit and earnings per share of 70 cents to 90 cents for 2005, on a recurring basis adjusted for the impact of mark-to-market accounting.

In 2006, Williams now expects consolidated segment profit of $1.520 billion to $1.820 billion on a recurring basis adjusted for the impact of mark-to-market accounting, compared with previous expectations of $1.515 billion to $1.815 billion for this measure.

In 2007, Williams now expects consolidated segment profit of $1.830 billion to $2.255 billion on a recurring basis adjusted for the impact of mark-to-market accounting, compared with previous expectations of $1.640 billion to $2.065 billion for this measure.

In 2008, Williams expects consolidated segment profit of $2.05 billion to $2.6 billion on a recurring basis adjusted for the impact of mark-to-market accounting.

Williams cited favorable prices for natural gas as the primary factor for increasing the company's consolidated segment profit forecasts.

The company's overall capital budget has increased, as well. It now plans to spend $1.2 billion to $1.35 billion for 2005; $1.825 billion to $2.050 billion for 2006; and $1.425 billion to $1.625 billion for 2007.

Previously, Williams forecasted capital spending of $1.1 billion to $1.3 billion for 2005; $1.525 billion to $1.750 billion for 2006; and $1.1 billion to $1.3 billion for 2007.

The $300 million increase in capital spending guidance for 2006 is budgeted for increased drilling costs and additional drilling in Exploration & Production, along with new infrastructure projects in Midstream.

Today's Analyst Call

Williams' management will discuss the company's third-quarter 2005 financial results and outlook during an analyst presentation to be webcast live beginning 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 (877) 502-9276. International callers should dial (913) 981-5591. Callers should dial in at least 10 minutes prior to the start of the discussion. Replays will be available at www.williams.com.

Form 10-Q

The company is filing its Form 10-Q today with the Securities and Exchange Commission. The document will be available on both the SEC and Williams websites.

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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(918) 573-3679

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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.*

In regard to the company's reserves in Exploration & Production, the SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We have used certain terms in this news release, such as "probable" reserves and "possible" reserves and "new opportunities potential" 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 reduced levels of certainty than for proved reserves. Possible reserve estimates are less certain than those for probable reserves. New opportunities potential is an estimate of reserves for new areas for which we do not have sufficient information to date to raise the reserves to either the probable category or the possible category. New opportunities potential estimates are even less certain that those for possible reserves. Reference to "total resource portfolio" include proved, probable and possible reserves as well as new opportunities potential. 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.

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

(Dollars in millions, except for per-share amounts)	2004					2005			
	1st Qtr	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*Year*
Income (loss) from continuing operations available to common stockholders	$ —	($ 18.5)	$ 16.2	$ 95.5	$ 93.2	$ 202.2	$ 40.7	$ 5.7	$ 248.6
Income (loss) from continuing operations — diluted earnings (loss) per common share	$ —	($ 0.03)	$ 0.03	$ 0.17	$ 0.17	$ 0.34	$ 0.07	$ 0.01	$ 0.42
Nonrecurring items:									
Power									
Accrual for a regulatory settlement (1)	—	—	—	—	—	4.6	—	—	4.6
Accrual for litigation contingencies (1)	—	—	—	—	—	—	13.1	0.4	13.5
Prior period correction	—	—	—	—	—	6.8	—	—	6.8
Total Power nonrecurring items	—	—	—	—	—	11.4	13.1	0.4	24.9
Gas Pipeline									
Prior period liability corrections — TGPL	—	—	—	—	—	(13.1)	(4.6)	—	(17.7)
Prior period pension adjustment — TGPL	—	—	—	—	—	—	(17.1)	—	(17.1)
Write-off of previously-capitalized costs — idled segment of Northwest's pipeline	—	9.0	—	—	9.0	—	—	—	—
Income from favorable ruling on FERC appeal (1999 Fuel Tracker)	—	—	—	—	—	—	—	(14.2)	(14.2)
Total Gas Pipeline nonrecurring items	—	9.0	—	—	9.0	(13.1)	(21.7)	(14.2)	(49.0)
Exploration & Production									
Gain on sale of E&P properties	—	—	—	—	—	(7.9)	—	(21.7)	(29.6)
Loss provision related to an ownership dispute	—	11.3	—	4.1	15.4	0.3	—	—	0.3
Total Exploration & Production nonrecurring items	—	11.3	—	4.1	15.4	(7.6)	—	(21.7)	(29.3)
Midstream Gas & Liquids									
La Maquina depreciable life adjustment	—	—	6.4	1.2	7.6	—	—	—	—
Gain on sale of Louisiana Olefins assets	—	—	—	(9.5)	(9.5)	—	—	—	—
Gulf Liquids arbitration award (Winterthur)	—	—	—	(93.6)	(93.6)	—	—	—	—
Impairment of Discovery	—	—	—	16.9	16.9	—	—	—	—
Devils Tower revenue correction	—	(16.5)	16.5		—	—	—	—	—
Total Midstream Gas & Liquids nonrecurring items	—	(16.5)	22.9	(85.0)	(78.6)	—	—	—	—
Other									
Impairment of Longhorn	—	10.8	—	—	10.8	—	49.1	—	49.1
Write-off of capitalized project development costs	—	—	—	—	—	—	4.0	—	4.0
Augusta environmental reserve	—	—	—	11.8	11.8	—	—	—	—
Longhorn recapitalization fee	6.5	—	—	—	6.5	—	—	—	—
Total Other nonrecurring items	6.5	10.8	—	11.8	29.1	—	53.1	—	53.1
Nonrecurring items included in segment profit (loss)	6.5	14.6	22.9	(69.1)	(25.1)	(9.3)	44.5	(35.5)	(0.3)
Nonrecurring items below segment profit (loss)									
Impairment of cost-based investments (Investing income (loss) -Various)	—	—	15.7	2.3	18.0	—	—	—	—
Write-off of capitalized debt expense (Interest accrued — Corporate)	—	3.8	—	—	3.8	—	—	—	—
Premiums, fees and expenses related to the debt repurchase and debt tender offer (Other income	—	96.7	155.1	29.7	281.5	—	—	—	—

(expense) — net — Corporate and Exploration & Production)									
Gulf Liquids arbitration award (Winterthur) — interest income — (Investing income / loss) — Midstream)	—	—	—	(9.6)	(9.6)	—	—	—	—
Gain on sale of remaining interests in Seminole Pipeline and MAPL (Investing income / loss — Midstream)	—	—	—	—	—	—	(8.6)	—	(8.6)
Loss provision related to an ownership dispute — interest component (Interest accrued — Exploration & Production)	—	1.9	—	2.1	4.0	2.7	—	—	2.7
Directors and officers insurance policy adjustment (General corporate expenses — Corporate)	—	—	—	—	—	—	—	13.8	13.8
Loss provision related to ERISA litigation settlement (Other income (expense) — net - Corporate)	—	—	—	—	—	—	—	5.0	5.0
	—	102.4	170.8	24.5	297.7	2.7	(8.6)	18.8	12.9
Total nonrecurring items	6.5	117.0	193.7	(44.6)	272.6	(6.6)	35.9	(16.7)	12.6
Tax effect for above items [1]	2.5	44.8	74.1	(17.1)	104.3	(2.8)	10.7	(6.4)	1.5
Recurring income (loss) from continuing operations available to common stockholders	$ 4.0	$ 53.7	$ 135.8	$ 68.0	$ 261.5	$ 198.4	$ 65.9	($ 4.6)	$ 259.7
Recurring diluted earnings (loss) per common share	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.49	$ 0.33	$ 0.11	($ 0.01)	$ 0.44
Weighted-average shares — diluted (thousands)	519,485	521,698	529,525	586,497	535,611	599,422	578,902	580,735	604,749

(1) No tax effect on $.6 million of the accrual for a regulatory settlement in 1st quarter 2005 and $8 million of the accrual for litigation contingencies in 2nd quarter 2005.

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.

Reconciliation of Mark-to-Market Adjustments

Dollars in millions except for per share amounts	2005 1Q	2005 2Q	2005 3Q	2005 4Q	2005 Year
Recurring income from cont. ops available to common shareholders	**$ 198**	**$ 66**	**$ (5)**		**$ 260**
Recurring diluted earnings per common share	**$ 0.33**	**$ 0.11**	**$ (0.01)**		**$ 0.44**
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(221)	(22)	153		(90)
Add realized gains/losses from MTM previously recognized	113	77	60		250
Total MTM adjustments	(108)	55	213		160
Tax effect of total MTM adjustments (at 39%)	(42)	21	83		62
After tax MTM adjustments	(66)	34	130		98
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 132**	**$ 100**	**$ 125**		**$ 357**
Recurring diluted earnings per share after MTM adj.	**$ 0.22**	**$ 0.17**	**$ 0.22**		**$ 0.60**
weighted average shares — diluted (thousands)	599,422	578,902	580,735		604,749

	2004 * 1Q	2004 * 2Q	2004 * 3Q	2004 * 4Q	2004 * Year
Recurring income from cont. ops available to common shareholders	**$ 4**	**$ 54**	**$ 136**	**$ 68**	**$ 261**
Recurring diluted earnings per common share	**$ 0.01**	**$ 0.10**	**$ 0.26**	**$ 0.12**	**$ 0.49**
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(24)	(70)	(187)	(23)	(304)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186
Total MTM adjustments	112	(59)	(142)	(29)	(118)
Tax effect of total MTM adjustments (at 39%)	44	(23)	(55)	(11)	(46)
After tax MTM adjustments	68	(36)	(87)	(17)	(72)
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 72**	**$ 18**	**$ 49**	**$ 50**	**$ 189**
Recurring diluted earnings per share after MTM adj.	**$ 0.14**	**$ 0.03**	**$ 0.09**	**$ 0.09**	**$ 0.35**
	519,485	521,698	529,525	586,497	535,611

Exhibit 99.2

Williams 2005 3rd Quarter Earnings Release

November 3, 2005

Williams

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 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.

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Oil & Gas Reserves Disclaimer

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Reference to "total resource portfolio" include proved, probable and possible reserves as well as new opportunities potential.

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 Web site at www.williams.com.

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3Q05 Review

Steve Malcolm
Chairman, President & CEO

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Overview

3rd Quarter Headlines

- Recurring earnings after mark-to-market effect climb nearly 150% over year-ago level
- Exploration & Production growth continues
- Continued strength in liquids margins drive Midstream results higher
- Gas Pipeline continues steady performance
- Mild weather, high gas prices, hurricanes combine to depress Power results

Overview

Headlines

- E&P ready to ramp up pace of growth again with arrival of new rigs in Piceance Basin
- Midstream captures significant deepwater production commitment, prepares to expand capacity in West
- Gas Pipeline continues to expand system to meet demand of growth markets
- Power completes deal to resell 1,500 megawatts of tolling rights through 2010
- Planning sale to Williams Partners L.P. of about 25% interest in gathering and processing assets in Four Corners area
- Raising capital expenditure and profit guidance

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Overview

Effect of Hurricanes

- Overall effect on Williams expected to be minimal
- Interstate pipelines provided continuous service
- For Midstream, Katrina and Rita reduced volumes in the Gulf of Mexico area, but boosted margins in its western business
- Moving incremental volumes - stranded gas - via new interconnects on Discovery
- Contributed to depressed Power results
- Pushed delivery of first of 10 new FlexRig4® rigs in Piceance Basin to end of this month

Financial Results and 2005 Outlook

Don Chappel
CFO

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Financial Results

Dollars in millions (except per share amounts)	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Income (Loss) from Continuing Operations	$5	$16	$249	($2)
Income (Loss) from Disc. Operations	(1)	83	(2)	92
Net Income (Loss)	$4	$99	$247	$90
Net Income (Loss)/Share	$0.01	$0.19	$0.42	$0.17
Recurring Income (Loss) from Cont. Ops./Share	($0.01)	$0.26	$0.44	$0.37
Recurring Inc. from Cont. Ops. After MTM Adjustments/Share	$0.22	$0. 09	$0.60	$0.27

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.

Recurring Income from Cont. Operations

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Income (Loss) from Continuing Operations	$6	$16	$249	($2)
Nonrecurring Items				
Impairments/Losses/Write-offs	5	16	61	41
Expense related to Prior Periods	-	17	(28)	11
Gain on Sale of Assets	(22)	-	(38)	-
Debt Retirement Expense	-	155	-	252
Other - Net	-	6	18	13
Total nonrecurring	(17)	194	13	317
Tax Effect of Adjustments	(6)	74	2	121
Recurring Income (Loss) from Continuing Operations Available To Common	($5)	$136	$260	$194
Recurring Income (Loss) from Continuing Operations/Share	($0.01)	$0.26	$0.44	$0.37

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. Operations After Mark-to-Market Adjustments

Dollars in millions, except for per-share amounts	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Recurring Inc. (Loss) from Cont. Ops. Avail. To Common	($5)	$136	$260	$194
Recurring Diluted Earnings (Loss) per Common Share	($0.01)	$0.26	$0.44	$0.37
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM (gains) losses	153	(187)	(90)	(280)
Add realized gains from MTM previously recognized	60	45	250	193
Total MTM adjustments	213	(142)	160	(87)
Tax Effect of Total MTM Adjustments (at 39%)	83	(55)	62	(34)
After-tax MTM Adjustments	130	(87)	98	(53)
Recurring income from Continuing Operations Avail. To Common Shareholders After MTM Adjustments	$125	$49	$358	$141
Recurring Diluted Earnings Per Share After MTM adjustments	$0.22	$0.09	$0.60	$0.27

Note:
Adjustments have been made to reverse estimated forward unrealized MTM gains (losses) and add estimated realized gains 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 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

	3rd Qtr		YTD	
	2005	2004	2005	2004
Segment Profit	$205	$436	$971	$1,008
Net Interest Expense	(164)	(197)	(491)	(657)
Debt Retirement expense	-	(155)	-	(252)
Other Income (Expense) - Net	(38)	(19)	(62)	(58)
Income from Cont. Ops. Before Tax	3	65	418	41
Provision for Income Tax	(2)	49	169	43
Income (Loss) from Continuing Ops.	5	16	249	(2)
Income (Loss) from Discontinued Ops.	(1)	83	(2)	92
Net Income	$4	$99	$247	$90

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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Third Quarter Segment Profit

Dollars in millions	Reported 3Q05	Reported 3Q04	Recurring 3Q05	Recurring 3Q04
Exploration & Production	$159	$70	$137	$70
Midstream Gas & Liquids	121	105	121	128
Gas Pipeline	161	149	147	149
Power	(226)	109	(226)	109
Other	(10)	3	(10)	3
Segment Profit	$205	$436	$169	$459
MTM Adjustments - Power			213	(142)
Segment Profit after MTM Adjustments			**$382**	**$317**
Memo:				
Power after MTM adjustments			**$(13)**	**$(33)**

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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2005 YTD Segment Profit

Dollars in millions	Reported 2005	Reported 2004	Recurring 2005	Recurring 2004
Exploration & Production	$38	$165	$352	$176
Midstream Gas & Liquids	359	314	359	320
Gas Pipeline	493	429	444	438
Power	(187)	121	(162)	121
Other	(75)	(21)	(23)	(3)
Segment Profit	$971	$1,008	$970	$1,052
MTM Adjustments			160	(87)
Segment Profit after MTM Adjustments			**$1,130**	**$965**
Memo:				
Power after MTM adjustments			**($2)**	**$34[1]**

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.

[1] Includes impact of legacy natural gas portfolio that liquidated in 1Q04.

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

Dollars in millions

Recurring Segment Profit after MTM Adj. 3Q04	**$317**
Exploration & Production	67
- Higher production volumes +$14million	
- Higher net realized price +$82 million	
- Impact of hedge ineffectiveness -$16 million	
Midstream	(7)
- Decreased NGL margins -$11 million	
- Increased processing fees +$7 million	
Gas Pipeline	(2)
- Increased Gulfstream earnings +$5 million	
- Grays Harbor contract termination -$5 million	
Power	20
- Absence of interest rate losses +$15 million	
Other	(13)
Recurring Segment Profit after MTM Adj. 3Q05	**$382**

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Cash Information

Dollars in millions	3Q05	YTD05
Beginning Unrestricted	**$ 1,297**	**$ 930**
Cash flow from Continuing Operations	289	1,082
Proceeds from Issuing Common[1]	7	303
Proceeds from sale of limited partnership units	111	111
Sale of WilTel Note	-	55
Contract Termination Payment	-	88
Debt Retirements	(23)	(244)
Capital Expenditures	(369)	(886)
Dividends	(43)	(100)
Other-Net	92	22
Change in Cash and Cash equivalents	$64	$431
Ending Unrestricted Cash at 9/30/05		$1,361[2]
Restricted Cash at 9/30/05 (not included above)		$85

[1] $273 MM of proceeds related to settlement of purchase contract underlying FELINE PACS
[2] Includes international cash ($197), cash to settle legacy matters including tax settlement ($200), AK Quality Bank judgment and other matters.

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Debt Balance[1]

Dollars in millions

		Avg. Cost
Debt Balance @ 12/31/04	**$7,962**	**7.4%**
Scheduled Debt Retirements & Amortization	(216)	
Capitalized Lease	4	
Debt Balance @ 3/31/05	**7,750**	**7.4%**
Scheduled Debt Retirements & Amortization	(6)	
Debt Balance @ 6/30/05	**7,744**	**7.5%**
Scheduled Debt Retirements & Amortization	(23)	
Debt Balance @ 9/30/05	**$7,721**	**7.5%**
Fixed Rate Debt @ 9/30/05	**$7,073**	**7.7%**
Variable Rate Debt @ 9/30/05	**$648**	**5.7%**

[1] *Debt is long-term debt due within 1 year plus long-term debt.*

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Business Unit Results

Exploration & Production

Ralph Hill
Senior Vice President

Williams

Exploration & Production

Segment Profit

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Segment Profit	**$159**	**$70**	**$381**	**$165**
Nonrecurring:				
Ownership Issue	-	-	-	11
Gain on sale of assets	(22)	-	(29)	-
Recurring Segment Profit	**$137**	**$70**	**$352**	**$176**

- **3Q04 to 3Q05 financial highlights include:**
  - Volume increase of 17%
  - Net realized price increase of 44%
  - Hedge ineffectiveness expense of $15.8MM in 3Q05
  - Recurring profit increase of 96%, excluding hedge ineffectiveness 119%
- **Base business sequential quarter improved**
  - Increased recurring segment profit 16%, excluding hedge ineffectiveness 30%
  - Increased volumes 5%
- **$94 million negative hedge impact in 3Q05 including $16 million hedge ineffectiveness, $186 million year to date**

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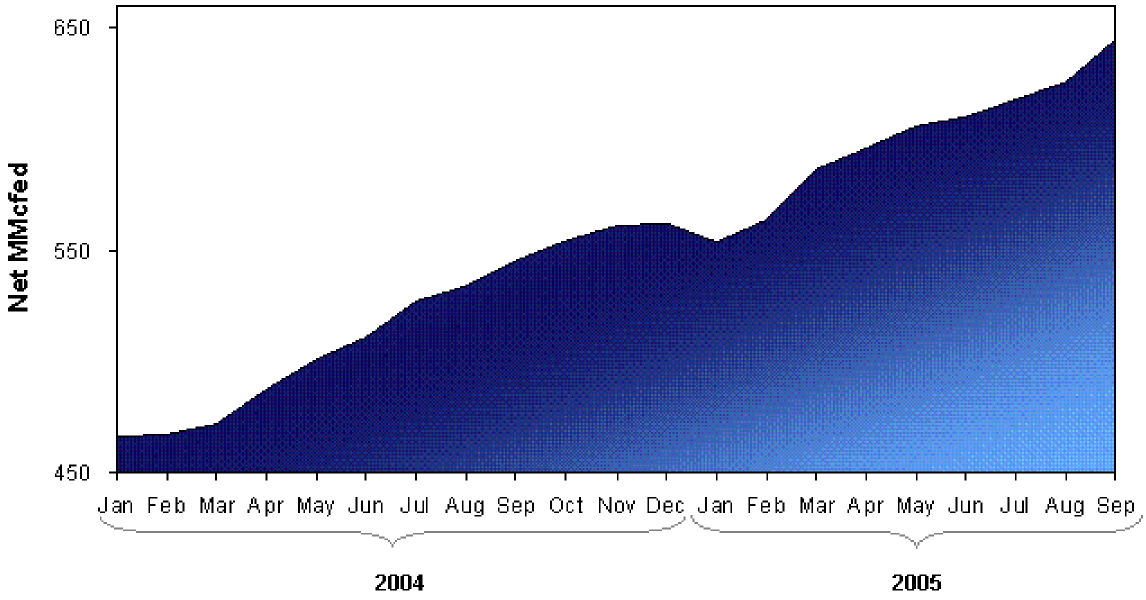
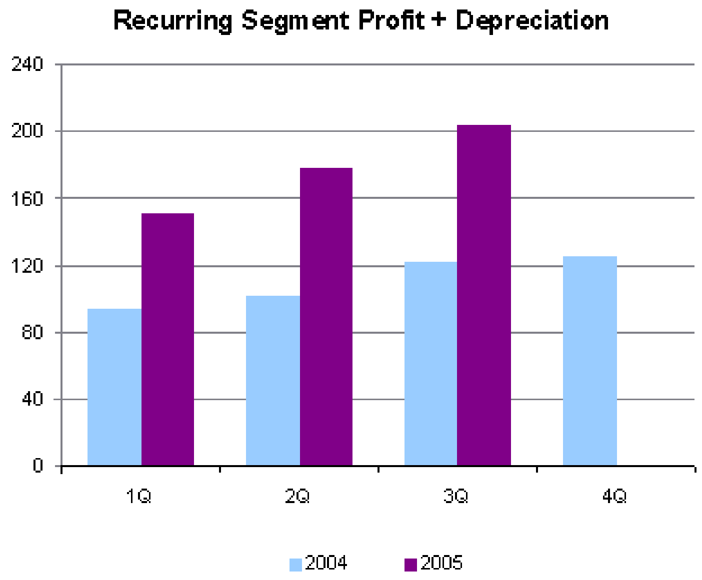
Strong Domestic Production Growth



Exploration & Production

3rd Quarter and 2005 Accomplishments

- Impressive volume growth continues
- Full year with no lost time accidents for E&P
- Big George gross production up to 135 MMcf/d
- 12 rigs operating in Piceance Valley, 3 rigs in Highlands
- First H&P rig to be delivered in November
- Highlands production reaches 13 MMcf/d
- Additional Piceance Highland opportunity obtained
- Ft. Worth progressing
- Stable San Juan production continues
- International volumes up 10% sequentially



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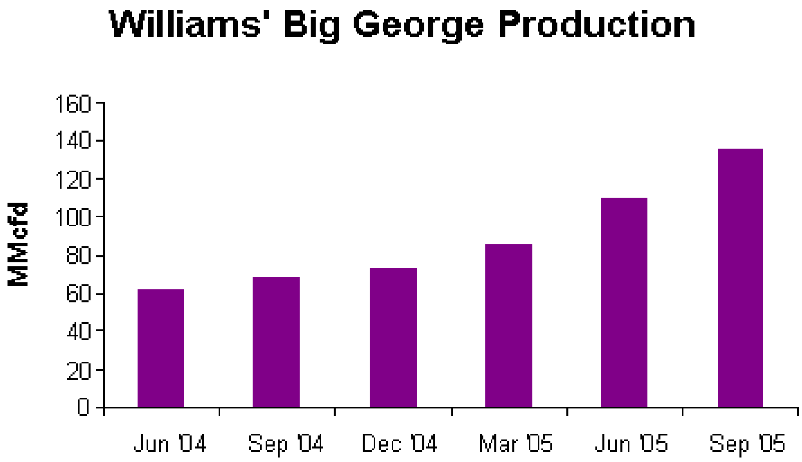
Exploration & Production

Powder River - Big George Coal Area

- Up 67 MMcf/d or 98% over a year ago
- Up 25 MMcf/d or 23% sequentially
- Big George production increase continues to offset Wyodak decline



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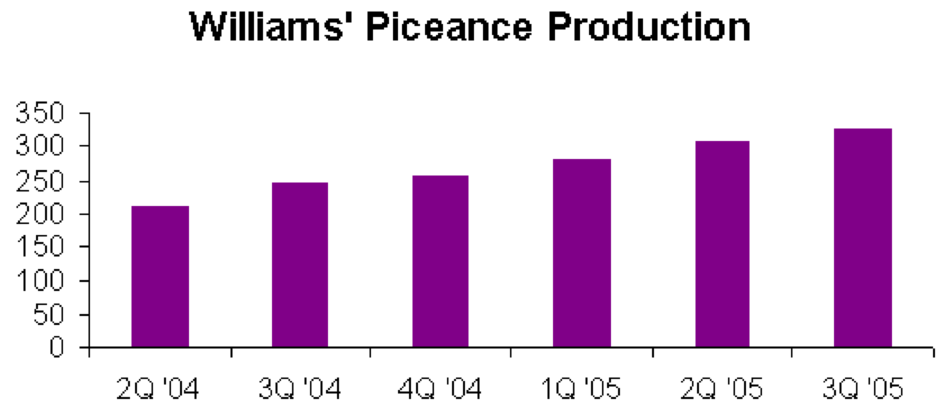
Exploration & Production

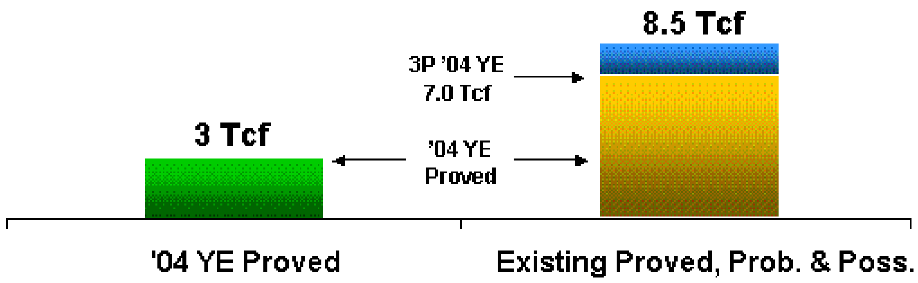
Piceance Production Growth

- Up 84 MMcf/d or 34% over a year ago
- Up 19 MMcf/d or 6% sequentially



Exploration & Production

3P Reserves



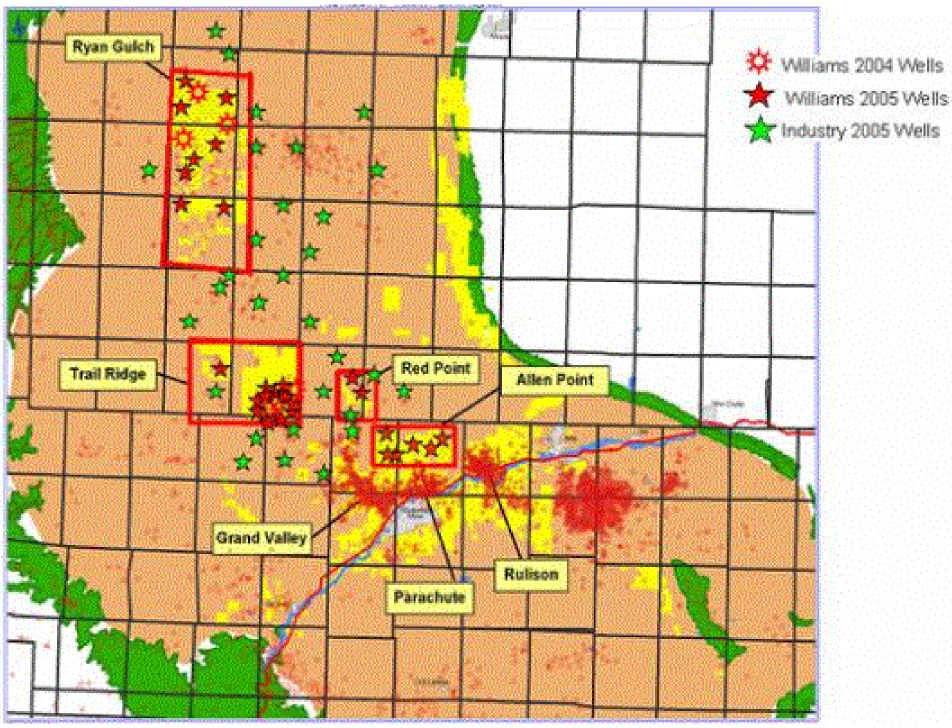
<u>August '05 Announcement:</u>

- 37.5% increase in probable and possible reserves since year end '04
- Extensive study of Piceance Valley yielded additional 1,600 locations and approximately 1.5 Tcf probable and possible reserves
  - Rock quality
  - Land/topography
  - Drilling reach
- H&P rig capabilities provide access to some of the additional locations
- Does not include areas such as Trail Ridge, Ryan Gulch, Red Point and Allen Point

Williams

Exploration & Production

Piceance Highlands – Operations Update



Piceance Highlands Projects Summary

Project Area	Net Acres	Estimated Gross Potential Locations	Estimated Net Potential Reserves (BCF) [1]	2004 Wells	2005 Wells	2006 Wells
Trail Ridge (40-acre density)[2]	20,638	500	500	3	12	20
Ryan Gulch (40-acre density)	15,780	770	700	3	8	15
Allen Point (40-acre density)	6,240	200	140	0	6	9
Red Point (10-acre density)	1,908	190	200	0	2	10
Total	**44,566**	**1,660**	**1,540**	**6**	**28**	**54**

[1] Not included in US Reserves summary of 3.0 Tcf proved and 8.5 Tcf proved, probable and possible
[2] 10-acre increased density hearing on COGCC docket for December 5, 2005

Exploration & Production

Piceance Highlands – Year to Date Results

Project Area	Wells Drilled / Completed	Average 30 Day Rate / Completed Well (MMCF/D)	Preliminary Reserves Range (BCF/well)
Trail Ridge	12 / 9	1.1	1.2 – 1.4
Ryan Gulch(1)	2 / 1	1.4	1.2 – 2.0
Red Point (2)	-	1.2	1.2 – 1.4
Allen Point	3 / 1	1.1	1.2 – 1.4

(1) Combination of our wells and offset wells from this year
(2) All Rates and reserve range estimates based on offset areas

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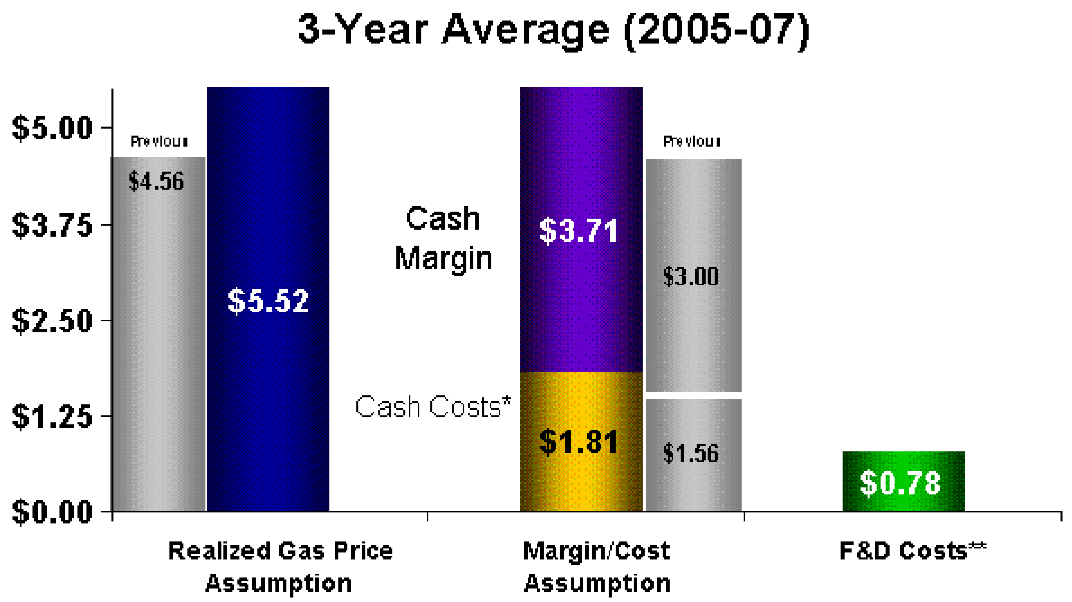
Exploration & Production

Cash Margin Analysis



Reflective of core basins

* Includes LOE, G&A, taxes and gathering

** Includes acquisition and development expenditures / proved reserves ('02-'04 average)

Williams

Exploration & Production

2005-2007 Guidance

Dollars in millions	2005	2006	2007
Segment profit	$575 - 600[1] *410 - 485*	$650 - 725 *520 - 595*	$775 - 900 *595 - 720*
Annual DD&A	235 - 265	335 - 375 *295 - 335*	425 - 475 *365 - 415*
Segment profit + DD&A	$810 - 865 *645 - 750*	$985 - 1,100 *815 - 930*	$1,200 - 1,375 *960 - 1,135*
Capital spending	$675 - 725 *605 - 680*	$950 - 1,050 *760 - 860*	$950 - 1,050 *735 - 885*
Production (MMcfe/d)	650 - 675 *625 - 700*	750 - 825 *740 - 840*	875 - 975 *850 - 950*
Unhedged Price Assumption (NYMEX, $/Mcf)	$8.70[2] *$6.34*	$8.50 *$5.96*	$7.00 *$5.75*
Hedge Volume (MMcfe/d)	383	414	287

1 Includes YTD nonrecurring adjustments which increase reported earnings by $29 million

2 $8.70 is average for 2005 and includes a $13.31 estimate for the 4th quarter

Note: If guidance has changed, previous guidance from 8/4/2005 is shown in italics directly below

Exploration & Production

2006-07 Guidance Reconciliation

Dollars in millions	2006		2007	
	Capital	Segment Profit	Capital	Segment Profit
Price/production		$170		$225
Increased industry costs	$100	(55)	$80	(80)
Total change to base	100	115	80	145
New Projects: Piceance Highlands, Ft. Worth, Facilities	90	15	110	35
Total Change	$190	$130	$190	$180

Williams

Key Points

- Strategy remains rapid development of our premier drilling inventory
- Delivering meaningful volume growth through expanded development drilling activity -- Piceance is primary growth driver
- 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
- New opportunities contributing
  - Trail Ridge, Ryan Gulch, Red Point, Allen Point, Ft. Worth Basin, and Caney Shale
- Experienced and talented workforce

Midstream

Alan Armstrong
Senior Vice President

Williams

Midstream

Segment Profit

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Segment Profit	$121	$105	$359	$314
Nonrecurring:				
Depreciable Life Adjustment	-	6		6
Devils Tower Revenue Recognition[1]	-	17	-	-
Recurring Segment Profit	$121	$128	$359	$320

Key Business Drivers:

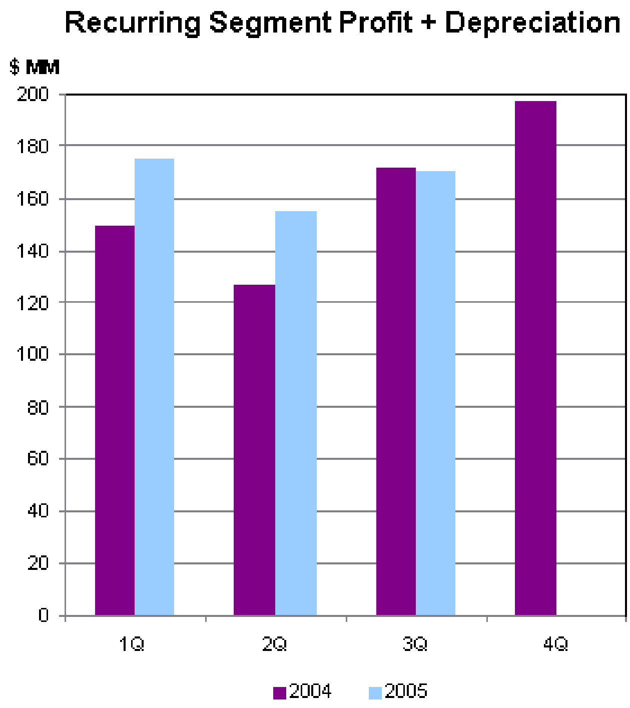
- Higher Gathering and Processing Fee Revenue
- Outages in Gulf Coast Drove High Western Margins
- Total NGL Production Lowered by Outages

[1] Recognition of revenue correction 2Q '04 to 3Q '04.

Williams

3rd Quarter and 2005 Highlights

- Rapidly responded to Katrina
- Providing industry solutions:
  - Discovery open seasons
- Damaged by Rita
  - Cameron Plant still down
- Max volume at Canada
- Won Tahiti Gulf of Mexico business
- Delivering promised expansions:
  - Opal TXP 5
  - Blind Faith
- 3rd quarterly increase in west gathered volumes & revenues



2005-07 Guidance

Dollars in millions	2005	2006	2007
Segment Profit	$440-480 *$400 - $470*	$400-500	$410-530 *$400 - $520*
Annual DD&A	180-190	185-195	195-205 *$190 - $200*
Segment Profit + DDA	$620-670 *$580 - $660*	$585-695	$605-735 *$590 - $720*
Capital Spending	$120-140	$230-250 *$110 - $130*	$180-220 *$100 - $130*

Major Growth Projects Update:

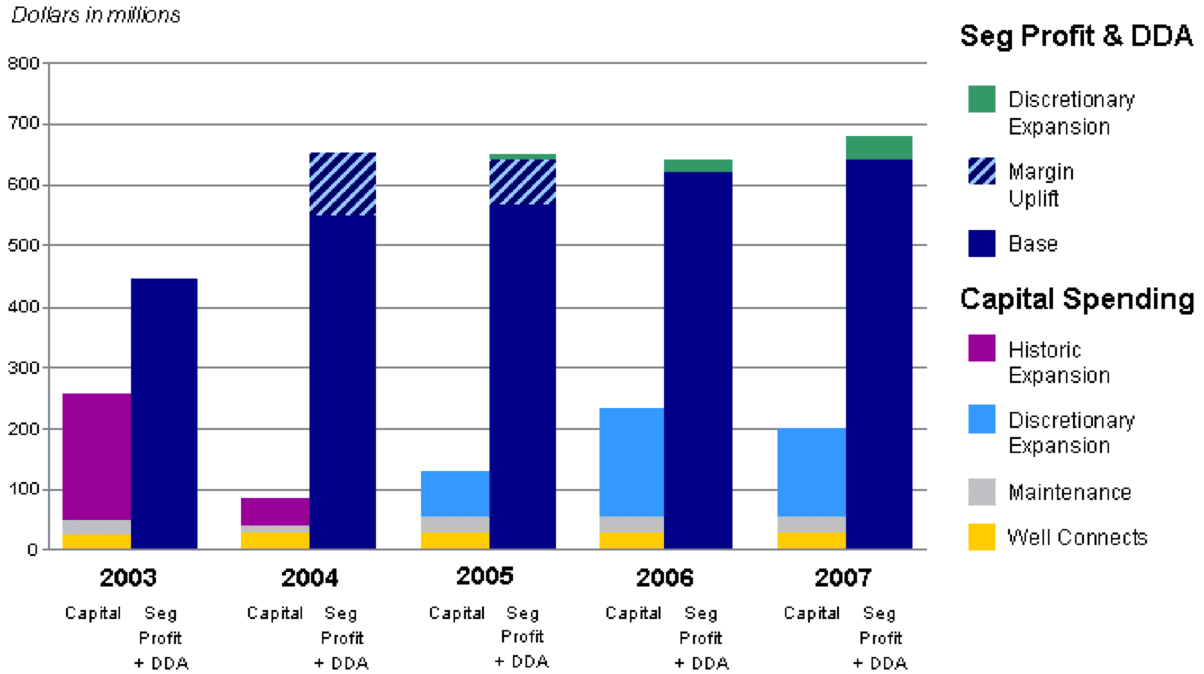
In Guidance	Identified '06-'07	Proposal Stage '06-'08
Opal TXP V (2Q 2007)	$200-300 MM	$600 MM
Blind Faith (3Q 2007)		

Note: If guidance has changed, previous guidance from 8/4/2005 is shown in italics directly below

Williams

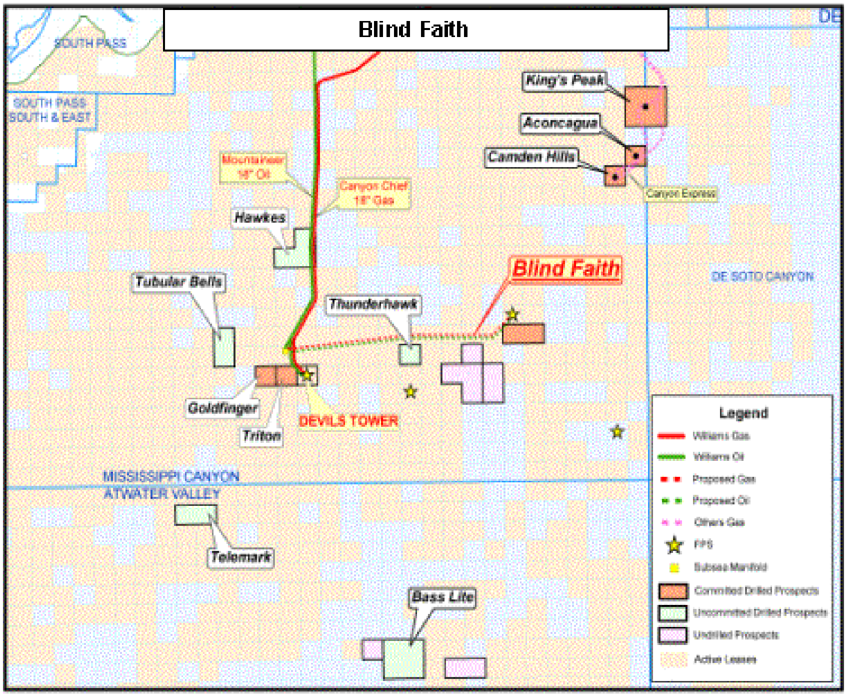
Midstream

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.
- Margin uplift represents actual realized margin in excess of forecasted margin.

Delivering Promised Expansions

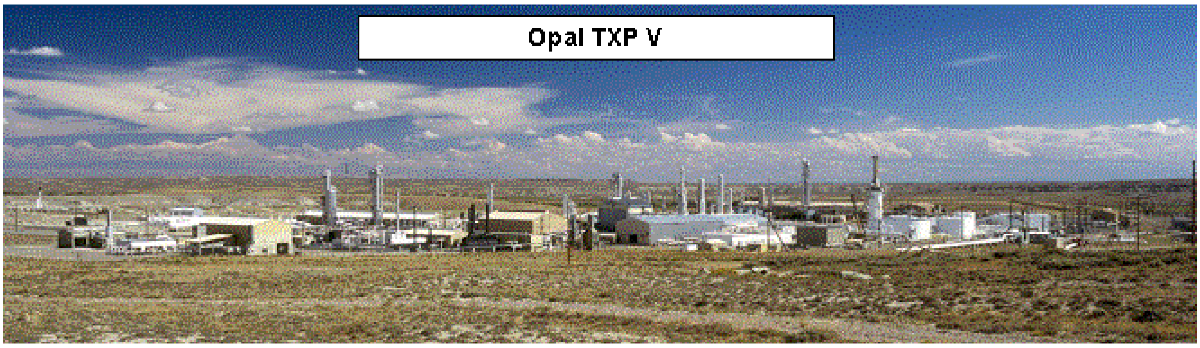


- $177 MM to extend Canyon Chief and Mountaineer 37 miles
- Expected to be ready for service by 3Q 2007
- Opportunity for gas processing at Mobile Bay
- Opportunity for gas transport through Transco and Gulfstream
- Liquids could be fractionated at Baton Rouge or Paradis

Williams

Midstream

Delivering Promised Expansions



- **Adding capacity:**
  - Gas processing ~ 350 MMcf/day
  - Liquids production ~ 17,000 BBls/day
- **Total post-expansion capacity:**
  - Gas processing ~ 1.5 Bcf/day
  - Liquids production ~ 68,000 BBls/day
- **In service by 2Q 2007**
- **Serving the Pinedale Anticline Field**

Midstream

Key Points

- Strong earnings and cash flows despite hurricanes
- MLP supplements growth strategy
- Capturing growth opportunities
  - Delivered on “First Tranche” of expansion opportunities
  - Organic growth around our Western assets
  - Footprint expansion in the deepwater
- Robust opportunities in the pipeline
- Midstream Tutorial on November 30

Gas Pipeline

Phil Wright
Senior Vice President

Gas Pipeline

Segment Profit

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Segment Profit	**$161**	**$149**	**$493**	**$429**
Nonrecurring				
1999 Fuel Tracker adjustment[1]	(14)	-	(14)	-
Pension expense reduction[1]	-	-	(17)	-
Adjustment to carrying value of certain liabilities[1]	-	-	(18)	-
Write-off hydrostatic testing	-	-	-	9
Recurring Segment Profit	**$147**	**$149**	**$444**	**$438**

- **3Q04 to 3Q05 financial highlights include:**
  - $5 million increased earnings at Gulfstream
  - $(5) million Gray's Harbor contract termination

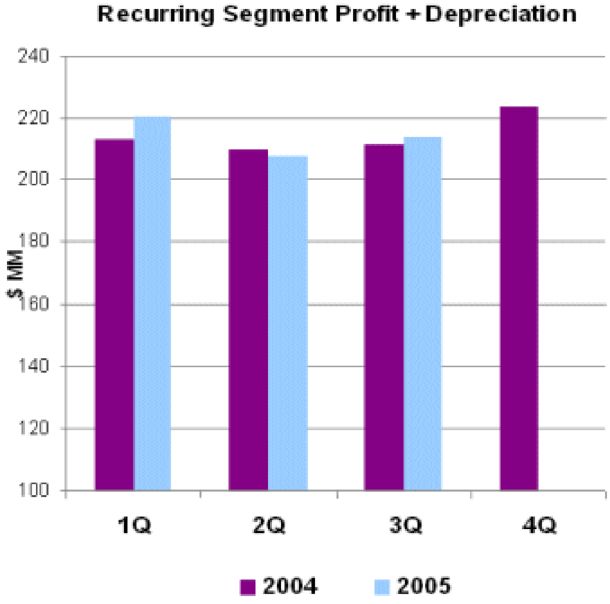
[1] Prior period items

Williams

Gas Pipeline

3rd Quarter and 2005 Accomplishments

- Northwest's 26" Replacement receives final FERC approval
- Transco and Gulfstream remained operational and met market demands throughout hurricane season
- Successful Gulfstream financing
- Successful in accelerating growth across our pipelines:
  - Gulfstream began new transportation service to Tampa Electric under new long-term firm service agreement for 48 Mdth/d
  - Construction began in July and wrapping up for Central New Jersey expansion project
  - Transco holds successful open season for the Potomac Expansion project in July
  - NWP announced an open season on the Parachute Lateral Project (Oct.)
  - Transco announced open season on the Sentinel Project (Nov.)



Gas Pipeline

2005-2007 Guidance

Dollars in millions	2005	2006	2007
Segment Profit	$630 - 645[1] *590 - 615*	$485 - 530[2,3] *500 - 565*	$585 - 655
Annual DD&A	270 - 280	290 - 300	300 - 310
Segment Profit + DDA	$900 - 925 *860 - 895*	$760 - 815 *790 - 865*	$885 - 965
Capital Spending	$390 - 420 *370 - 420*	$600 - 680[3] *600 - 700*	$300 - 390 *250 - 325*

1 ***Includes:***

YTD nonrecurring items which increase reported earnings by $49 million

2 ***Includes:***

- ***Pipeline Safety Costs of $31 million previously capitalized (see note 3)***
- ***Higher interest expense of $20 million at Gulfstream as a result of the October $850 million financing***
- ***No nonrecurring or one-time items***
- ***Higher expenses than 2005***

3 ***Impact of Pipeline Safety Improvement Act accounting rule reflected. Assumes $31 million of lower capital offset by $31 million of higher expenses.***

Note: If guidance has changed, previous guidance from 8/04/05 is shown in italics directly below

Williams

Gas Pipeline

2005-2007 Capital Spending Detail

Dollars in millions	2005	2006	2007
Normal Maintenance/ Compliance	$325 - 335 *305 - 335*	$305 - 370 *310 - 400*	$180 - 235
NWP 26" Replacement	48	276	2
Expansion[1]	20 - 30	20 - 35 *10 - 20*	120 - 155 *70 - 90*
Total	$390 - 420 *370 - 420*	$600 - 680 *600 - 700*	$300 - 390 *250 - 325*

[1] **Major Growth Projects (in guidance):**	**2005**	**2006**	**2007**
Central New Jersey (in-service 11/05)	$10 - 15		
Leidy to Long Island (in-service 11/07)	$ 5 - 10	$10 - 20	$75 - 95
Potomac Expansion (in-service 11/07)		$ 5 - 10	$45 - 65

Note: Sum of ranges may not add due to rounding

Williams

Gas Pipeline

Key Points

- Strong performance continues; operationally and financially
- Strong cash flow provider
- Continued progress
  - Compliance and reliability projects
  - Expansion developments
- Preparation for rate cases on schedule to be in effect 2007

Power

Bill Hobbs
Senior Vice President

Williams

Power

Segment Profit

Dollars in millions	3rd Qtr 2005	3rd Qtr 2004	YTD 2005	YTD 2004
Gross Margin (Includes MTM)	($203)	$131	($98)	$202
SG&A	(21)	(20)	(54)	(56)
Operating & Other Inc./(Expense)	(2)	(2)	(35)	(25)
Segment Profit/(Loss) (Includes MTM)	(226)	109	(187)	121
MTM Adjustments	201	(142)	149	(87)
Segment Profit/(Loss) After MTM Adjustments	($25)	($33)	($38)	$34
Segment Profit/(Loss) (Includes MTM)	($226)	$109	($187)	$121
Nonrecurring:				
Expense related to Settlements and Litigation Contingencies	0	0	13	0
Expense related to prior period	0	0	12	0
Recurring Segment Profit/(Loss)	(226)	109	(162)	121
MTM Adjustments (recurring)	213	(142)	160	(87)
Recurring Segment Profit/(Loss) After MTM Adjustments	($13)	($33)	($2)	$34

Note: MTM Adjustments (recurring) excludes $12mm paid in 3Q05 for buyout of gas supply contract

Power

YTD - Segment Profit to Cash Flow

Dollars in Millions	Power and Natural Gas	Other	Total YTD
Gross Margin	($98)		($98)
SG&A & Other Inc/(Exp)	(89)		(89)
Segment Profit/(Loss) [1]	**(187)**	**0**	**(187)**
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(101)		(101)
Add Realized Gains from MTM previously recognized	250		250
Segment Profit/(Loss) after MTM Adjustments [1]	**(38)**	**0**	**(38)**
Total Working Capital Change	0	82	82
Power Segment CFFO [1]	**(38)**	**82**	**44**
Est. Working Capital Used for Other BU's	0	(39)	(39)
Power Segment Standalone CFFO	**($38)**	**$43**	**$5**

[1] Includes YTD nonrecurring adjustments which decrease reported Segment Profit by $25 million and reported Segment Profit after MTM Adjustments and CFFO by $37million. Power Segment Profit after MTM Adjustments and Power Segment Standalone CFFO would be $36 million higher on a recurring basis. 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.

Williams

Items Impacting 3Q Performance

Dollars in millions

Segment Profit After MTM Adjustments:

Q305 Forecast (as of 6/30/05)	**$54**
▪ Estimated impact of mild weather in the West:	(30)
▪ Cooling Degree Days (CDDs) at Los Angeles (LAX) YTD are 17% below 5 yr avg and 43% below '04	
▪ Average September peak load in Cal-ISO system 13% below 2004	
▪ Estimated impact of higher NG prices, hurricanes & others	(25)
▪ Estimated impact of plant outages	(12)
▪ Buyout of gas supply contract	(12)
Q305 Segment Profit After MTM Adjustments	**($25)**

Power

Cash Flow Analysis

Undiscounted dollars in millions (GAAP Measure)

Combined Power Portfolio *Actual v. Forecast 3Q'05*	Q3'05A	Q3'05F	YTD05A	YTD05F
Tolling Demand Payment Obligations	($126)	($126)	($310)	($310)
Resale of Tolling	34	14	116	87
Full Requirements	(6)	0	(1)	6
Long-term Physical Forward Power Sales	3	10	46	54
OTC Hedges	13	4	89	74
Est. Tolling Cash Flows Associated with Hedges Estimated Merchant Cash Flows	88	117 60	123	165 64
Subtotal Cash Flows	7	79	64	142
NG & Other Commodity	(8)	(6)	(13)	(7)
SG&A and Other	(24)	(18)	(89)	(54)
Working Capital & Other	(15)	(7)	82	83
Power segment CFFO	(40)	48	44	164
Est. Working Capital Used for Other BU's	16	0	(39)	0
Power Standalone Cash Flows	($24)	$48	$5	$164

Note: 3Q05 forecast estimated as of 12/30/04. 3Q05 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.

Note: Estimated Cash Flows includes YTD nonrecurring adjustments which decrease reported cash flows by $36 million. Estimated cash flows would be $36million higher on a recurring basis.

Power

2005-07 Guidance

Dollars in millions	2005	2006	2007
Prior Segment Profit Guidance	($50) - 50	($270) - (120)	($220) - (70)
MTM Earnings (3Q05)	(141)		
Est. Forward MTM Impact	50	50	40
Chg due to Mkt Conditions, New deals & Other	(108)	0 - (50)	
Total Impact	(199)	50 - 0	40
Change in Segment Profit Guidance	(200)	50 - 0	40
Segment Profit Guidance	(225) - (175)	(225) - (125)	(180) - (30)
Estimated MTM Adjustments	175	270	230
	75	*320*	*270*
Reported Segment Profit after MTM Adj	(50) - 0	50 - 150	50 - 200
	25 - 125	*50 - 200*	
Non-Recurring	25	0	0
Recurring Segment Profit after MTM Adj	(25) - 25	50 - 150	50 - 200
	50 - 150	*50 - 200*	
Cash Flow from Operations	25 - 75	50 - 150	0 - 200
	50 - 150	*50 - 200*	
Capital Expenditures	-	-	-

Note: If guidance has changed, previous guidance from 2nd quarter is shown in italics directly below

New Power Contracts – 2005 Highlights

- **Deals Consummated Around Each Toll**
- **All Customer Classes Have Been Represented**
  - Utilities
  - Co-ops & Munis
  - Hedge funds & banks
- **Favorable Credit Terms**
  - Zero margining provisions in two deals in excess of 4 years
  - Margin Caps in place for approx. 2000 MW of toll resell
  - Lower margining agreements and netting will result in lower margin working capital

Power

2005 Successes

- **West**
  - 1,500 MW resale of tolling from AES 4000: 854 MW starting in 2006 and growing to 1,500 MW in 2007-10
  - 490-MW resale of toll from AES 4000 for 2006-08
  - 100-MW heat rate call option for 2008
  - 690-MW capacity sales: from AES 4000 for June-Sept 2005
  - 1,500 MW resale of tolling from AES 4000: 854 MW starting in 2006 and growing to 1,500 MW in 2007-10
  - Resale of tolling as a percentage of expected output: '06-67%, '07-85%, '08-81%, '09-68%, '10-68%
- **Mid-Continent**
  - 500 MW heat rate-priced energy and capacity sale to CLECO utility starting in 2006-09 (approval pending)
  - 100 MW heat-rate call option for 5 years – 2009 (Kinder toll)
  - 244-MW (max) block heat rate-priced energy sale for June-Sept 2005
- **Northeast**
  - 100-MW capacity sale from Ironwood to municipality for June 2005-May 2006
  - 1,000 MW of heat-rate call options sold through 2006

2005 Forecast: Recurring Segment Profit After MTM Adjustments

Dollars in millions

Recurring Segment Profit After MTM Adjustments:

2005 Full Year Forecast	**$(25) - 25**
■ Estimated cash flows from new hedges	50 - 60
■ Estimated improvement in weather	15 - 55
■ Reduced plant outages	10 - 10
2006 Full Year Forecast	**$50 - 150**

Power

Key Points

- **Results for 3rd quarter impacted by**
  - Mild weather in west
  - Unplanned outage in east
  - Hurricanes and high natural gas prices
- **CFFO YTD positive**
- **Full year recurring segment profit guidance is at break even despite higher NG prices and weak market conditions.**
- **Deal flow has increased as previously shown.**
- **Power Tutorial on November 30**

2005-07
Consolidated Outlook

Don Chappel
CFO

Consolidated

2005 Forecast Guidance

Dollars in millions, except per-share amounts	**Nov 3 Guidance**	**Aug 4 Guidance**
Segment profit before MTM adjustment	**$1,375 - $1,525**	$1,300 - $1,585
Net Interest Expense	(650) - (670)	(650) - (670)
Other (Primarily General Corp. Costs)	(70) - (100)	(70) - (100)
Pretax Income	655 - 755	580 - 815
Provision for Income Tax	(260) - (300)	(220) - (335)
Income from Continuing Ops	395 - 455	360 - 480
Income/(Loss) from Discontinued Ops	(10) - 0	(10) - 0
Net Income	**$385 - 455**	$350 - 480
Diluted EPS	**$0.64 - $0.75**	$0.58 - $0.79
Recurring Income from Cont. Ops	**$402 - $462**	$377 - $497
Diluted EPS – Recurring	**$0.66 - $0.76**	$0.62 - $0.82
Diluted EPS – Recurring After MTM Adjustments [1]	**$0.84 - $0.94**	$0.70 - $0.90

[1] *Includes MTM adjustment of $75 million (pretax) in Aug 4 guidance and $175 million (pretax) in Nov 3 guidance*

Note: Fully diluted shares of 605 million used in Aug 4 guidance and Nov 3 guidance

Williams

Consolidated

2005-07 Segment Profit

Dollars in millions	2005	2006	2007
Exploration & Production	$575 - 600 410 - 485	$650 - 725 520 - 595	$775 - 900 595 - 720
Midstream	440 - 480 400 - 470	400 - 500	410 - 530 400 - 520
Gas Pipeline	630 - 645 590 - 615	485 - 530 500 - 565	585 - 655
Power	(225) - (175) (50) - 50	(225) - (125) (270) - (120)	(180) - (30) (220) - (70)
Other / Corp. / Rounding	(45) - (25) (50) - (35)	(60) - (80) 45 - (45)	10 - (30)
Total	**$1,375 - 1,525** 1,300 - 1,585	**$1,250 - 1,550** 1,195 - 1,495	**$1,600 - 2,025** 1,370 - 1,795
MTM Adjustment	175 75	270 320	230 270
Total After MTM Adj.	**$1,550 - 1,700** 1,375 - 1,660	**$1,520 - 1,820** 1,515 - 1,815	**$1,830 - 2,255** 1,640 - 2,065

Note: If guidance has changed, previous guidance from 8/4/05 is shown in italics directly below

Consolidated

2005-07 Capital Expenditures

Dollars in millions	2005	2006	2007
Exploration & Prod.	**$675 - 725** 605 - 680	**$950 - 1,050** 760 - 860	**$950 - 1,050** 735 - 885
Midstream	**120 - 140**	**230 - 250** 110 - 130	**180 - 220** 100 - 130
Gas Pipeline	**390 - 420** 370	**600 - 680** 700	**300 - 390** 250 - 325
Power	**-**	**-**	**-**
Other/Corporate	**10 - 30**	**10 - 30**	**10 - 30**
Total	**$1,200 - 1,350** 1,100 - 1,300	**$1,825 - 2,050** 1,525 - 1,750	**$1,425 - 1,625** 1,100 - 1,300

Notes:
- Sum of ranges for each business line does not necessarily match total range
- If guidance has changed, previous guidance from 8/4/05 is shown in italics directly below

Williams

Consolidated

2005-07 Outlook

Dollars in millions	2005	2006	2007
Segment Profit			
Reported Seg. Profit	$1,375 - 1,525 [1] *1,300 - 1,585*	$1,250 - 1,550 *1,195 - 1,495*	$1,600 - 2,025 *1,370 - 1,795*
MTM Adjustment	175 *75*	270 *320*	230 *270*
After MTM Adjust.	1,550 - 1,700 *1,375 - 1,660*	1,520 - 1,820 *1,515 - 1,815*	1,830 - 2,255 *1,640 - 2,065*
DD&A	700 - 775	790 - 890 *770 - 870*	900 - 1,000 *840 - 940*
Cash Flow from Ops.	1,325 - 1,525 *1,150 - 1,450*	1,625 - 1,925 *1,550 - 1,850*	1,850 - 2,150 *1,650 - 1,950*
Capital Expenditures	1,200 - 1,350 *1,100 - 1,300*	1,825 - 2,050 *1,525 - 1,750*	1,425 - 1,625 *1,100 - 1,300*
Operating Free Cash Flow [1]	125 - 175 *50 - 150*	(200) - (125) *25 - 100*	425 - 525 *550 - 650*

[1] Operating free cash flow is defined as cash flow from operations less capital expenditures, before dividend or principal payments

Note: If guidance has changed, previous guidance from 8/4/05 is shown in italics directly below

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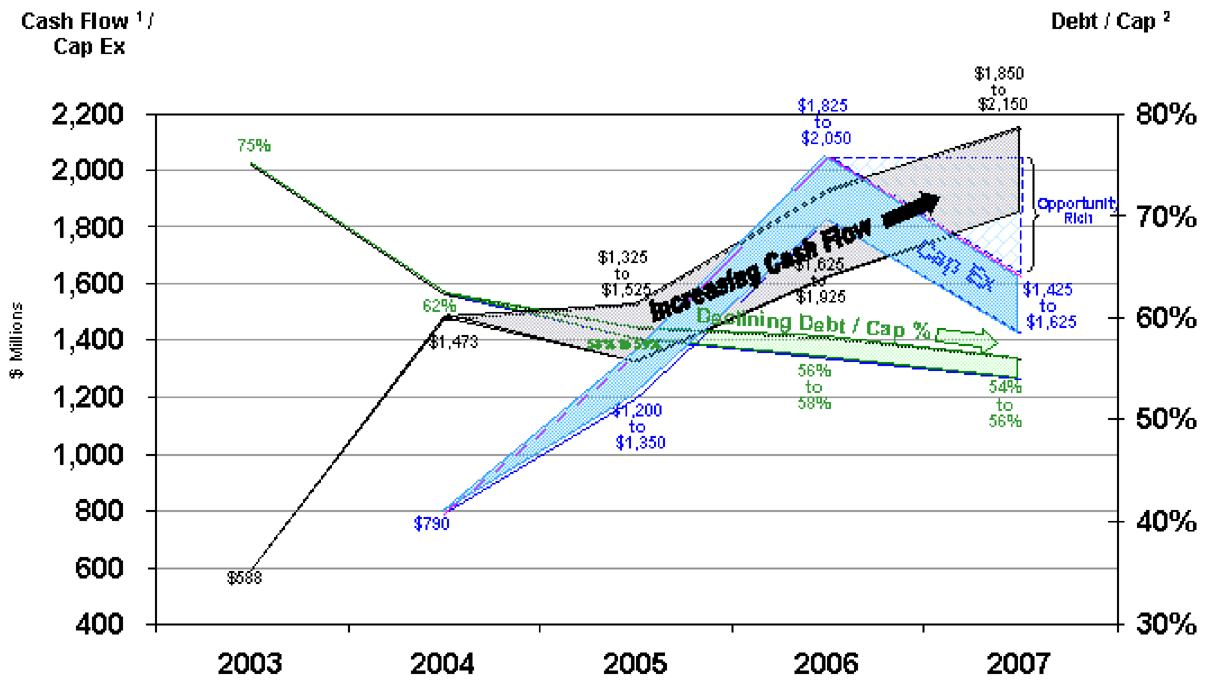
Strong Operating Cash Flow Growth & Increasing Investment Opportunities . . .



[1] Cash Flow from Continuing Operations (CFFO)
[2] Debt to Capitalization = Total Debt / (Total Debt + Equity)

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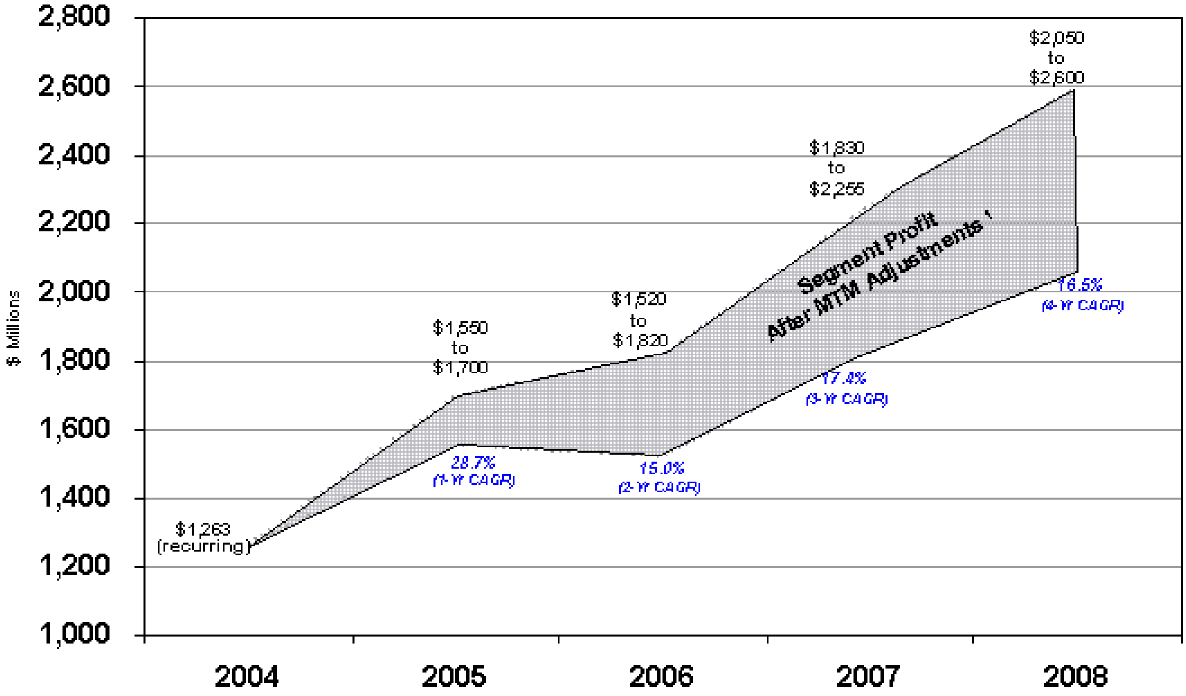
Segment Profit Guidance Trend



[1] Includes MTM adjustments of ($118) in 2004, $175 in 2005, $270 in 2006, $230 in 2007, and $167 in 2008.

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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**
- **Opportunity rich**
  - Increasing focus and disciplined EVA®-based investments in natural gas businesses
  - Attractive EVA-adding opportunities may require new capital
  - If new capital is needed, choose optimal sources of capital
  - Combination of growth in operating cash flows and EVA drives value creation

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Summary

Steve Malcolm
Chairman, President & CEO

Summary

Key Points

- Current growth activity continues to move key performance measures up
- Investing in future growth
- First planned sale to Williams Partners to deliver growth capital while retaining asset control
- Scope, scale of growth opportunities continues to expand
- Raising earnings, cash guidance; expect upward trend to make sharper incline in 2008

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 Schedule

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

(Dollars in millions, except for per-share amounts)	2004 1st Qtr	2004 2nd Qtr	2004 3rd Qtr	2004 4th Qtr	2004 Year	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 Year
Income (loss) from continuing operations available to common stockholders	$ -	($18.5)	$16.2	$95.5	$93.2	$202.2	$40.7	$5.7	$248.6
Income (loss) from continuing operations - diluted earnings (loss) per common share	$ -	($0.03)	$0.03	$0.17	$0.17	$0.34	$0.07	$0.01	$0.42
Nonrecurring items:									
Power									
Accrued for a regulatory settlement [1]	-	-	-	-	-	4.6	-	-	4.6
Accrued for litigation contingencies [1]	-	-	-	-	-	-	13.1	0.4	13.5
Prior period correction	-	-	-	-	-	6.8	-	-	6.8
Total Power nonrecurring items	-	-	-	-	-	11.4	13.1	0.4	24.9
Gas Pipeline									
Prior period liability corrections - TGPL	-	-	-	-	-	(13.1)	(4.6)	-	(17.7)
Prior period pension adjustment - TGPL	-	-	-	-	-	-	(17.1)	-	(17.1)
Write-off of previously-capitalized costs - idled segment of Northwest's pipeline	-	9.0	-	-	9.0	-	-	-	-
Income from favorable ruling on FERC appeal (1999 Fuel Tracker)	-	-	-	-	-	-	-	(14.2)	(14.2)
Total Gas Pipeline nonrecurring items	-	9.0	-	-	9.0	(13.1)	(21.7)	(14.2)	(49.0)
Exploration & Production									
Gain on sale of E&P properties	-	-	-	-	-	(7.9)	-	(21.7)	(29.6)
Loss provision related to an ownership dispute	-	11.3	-	4.1	15.4	0.3	-	-	0.3
Total Exploration & Production nonrecurring items	-	11.3	-	4.1	15.4	(7.6)	-	(21.7)	(29.3)
Midstream Gas & Liquids									
La Maquina depreciable life adjustment	-	-	6.4	1.2	7.6	-	-	-	-
Gain on sale of Louisiana Olefins assets	-	-	-	(9.5)	(9.5)	-	-	-	-
Gulf Liquids arbitration award (Winterline)	-	-	-	(93.6)	(93.6)	-	-	-	-
Impairment of Discovery	-	-	-	16.9	16.9	-	-	-	-
Devils Tower revenue correction	-	(16.5)	16.5	-	-	-	-	-	-
Total Midstream Gas & Liquids nonrecurring items	-	(16.5)	22.9	(85.0)	(78.6)	-	-	-	-
Other									
Impairment of Longhorn	-	10.8	-	-	10.8	-	49.1	-	49.1
Write-off of capitalized project development costs	-	-	-	-	-	-	4.0	-	4.0
Augusta environmental reserve	-	-	-	11.8	11.8	-	-	-	-
Longhorn recapitalization fee	6.5	-	-	-	6.5	-	-	-	-
Total Other nonrecurring items	6.5	10.8	-	11.8	29.1	-	53.1	-	53.1
Nonrecurring items included in segment profit (loss)	6.5	14.6	22.9	(69.1)	(25.1)	(9.3)	44.5	(35.5)	(0.3)
Nonrecurring items below segment profit (loss)									
Impairment of cost based investments (Investing income (loss) - Various)	-	-	15.7	2.3	18.0	-	-	-	-
Write-off of capitalized debt expense (Interest accrued - Corporate)	-	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)	-	96.7	155.1	29.7	281.5	-	-	-	-
Gulf Liquids arbitration award (Winterline) - interest income - (Investing income / loss) - Midstream	-	-	-	(9.6)	(9.6)	-	-	-	-
Gain on sale of remaining interests in Seminole Pipeline and MAPL (Investing income / loss - Midstream)	-	-	-	-	-	-	(8.6)	-	(8.6)
Loss provision related to an ownership dispute - interest component (Interest accrued - Exploration & Production)	-	1.9	-	2.1	4.0	2.7	-	-	2.7
Directors and officers insurance policy adjustment (General corporate expenses - Corporate)	-	-	-	-	-	-	-	13.8	13.8
Loss provision related to ERISA litigation settlement (Other income (expense) - net - Corporate)	-	-	-	-	-	-	-	5.0	5.0
	-	102.4	170.8	24.5	297.7	2.7	(8.6)	18.8	12.9
Total nonrecurring items	6.5	117.0	193.7	(44.6)	272.6	(6.6)	35.9	(16.7)	12.6
Tax effect for above items [1]	2.5	44.8	74.1	(17.1)	104.3	(2.8)	10.7	(6.4)	1.5
Recurring income (loss) from continuing operations available to common stockholders	$4.0	$53.7	$135.8	$68.0	$261.5	$198.4	$65.9	($4.6)	$259.7
Recurring diluted earnings (loss) per common share	$0.01	$0.10	$0.26	$0.12	$0.49	$0.33	$0.11	($0.01)	$0.44
Weighted-average shares - diluted (thousands)	519,465	521,698	529,525	566,497	535,611	599,422	578,902	580,735	604,749

[1] No tax effect on $4.6 million of the accrual for a regulatory settlement in 1st quarter 2005 and $8 million of the accrual for litigation contingencies in 2nd quarter 2005.

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.

Non-GAAP Reconciliation Schedule

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

(UNAUDITED)

(Dollars in millions)	2004 1st Qtr	2004 2nd Qtr	2004 3rd Qtr	2004 4th Qtr	2004 Year	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 Year
Segment profit (loss):									
Power [1]	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7	$ 114.1	$ (75.0)	$ (226.4)	$ (187.3)
Gas Pipeline	147.4	132.8	148.8	156.8	585.8	167.4	164.5	161.1	493.0
Exploration & Production	51.5	43.3	70.1	70.9	235.8	103.7	118.3	158.8	380.8
Midstream Gas & Liquids	110.1	98.5	105.4	235.7	549.7	128.6	109.1	121.1	358.8
Other	(8.7)	(14.3)	2.4	(21.0)	(41.6)	(4.1)	(90.5)	(10.1)	(104.7)
Total segment profit	$ 268.3	$ 304.1	$ 436.0	$ 398.0	$ 1,406.4	$ 509.7	$ 226.4	$ 204.5	$ 940.6
Nonrecurring adjustments:									
Power	$ -	$ -	$ -	$ -	$ -	$ 11.4	$ 13.1	$ 0.4	$ 24.9
Gas Pipeline	-	9.0	-	-	9.0	(13.1)	(21.7)	(14.2)	(49.0)
Exploration & Production	-	11.3	-	4.1	15.4	(7.6)	-	(21.7)	(29.3)
Midstream Gas & Liquids	-	(16.5)	22.9	(85.0)	(78.6)	-	-	-	-
Other	6.5	10.8	-	11.8	29.1	-	53.1	-	53.1
Total segment nonrecurring adjustments	$ 6.5	$ 14.6	$ 22.9	$ (69.1)	$ (25.1)	$ (9.3)	$ 44.5	$ (35.5)	$ (0.3)
Recurring segment profit (loss):									
Power	$ (32.0)	$ 43.8	$ 109.3	$ (44.4)	$ 76.7	$ 125.5	$ (61.9)	$ (226.0)	$ (162.4)
Gas Pipeline	147.4	141.8	148.8	156.8	594.8	154.3	142.8	146.9	444.0
Exploration & Production	51.5	54.6	70.1	75.0	251.2	96.1	118.3	137.1	351.5
Midstream Gas & Liquids	110.1	82.0	128.3	150.7	471.1	128.6	109.1	121.1	358.8
Other	(2.2)	(3.5)	2.4	(9.2)	(12.5)	(4.1)	(37.4)	(10.1)	(51.6)
Total recurring segment profit	$ 274.8	$ 318.7	$ 458.9	$ 328.9	$ 1,381.3	$ 500.4	$ 270.9	$ 169.0	$ 940.3

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

[1] Power's segment profit for 2004 includes the effect of intercompany interest rate swaps entered into with the parent company.

Non-GAAP Reconciliation

Non-GAAP Reconciliation Schedule

Dollars in millions except for per share amounts	2005 1Q	2005 2Q	2005 3Q	2005 4Q	2005 Year
Recurring income from cont. ops available to common shareholders	$ 198	$ 66	$ (5)		$ 260
Recurring diluted earnings per common share	$ 0.33	$ 0.11	$ (0.01)		$ 0.44
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(221)	(22)	153		(90)
Add realized gains/losses from MTM previously recognized	113	77	60		250
Total MTM adjustments	(108)	55	213		160
Tax effect of total MTM adjustments (at 39%)	(42)	21	83		62
After tax MTM adjustments	(66)	34	130		98
Recurring income from cont. ops available to common shareholders after MTM adjust	$ 132	$ 100	$ 125		$ 357
Recurring diluted earnings per share after MTM adj.	$ 0.22	$ 0.17	$ 0.22		$ 0.60
Weighted average shares - diluted (thousands)	599,422	578,902	580,735		604,749

	2004 ^ 1Q	2004 ^ 2Q	2004 ^ 3Q	2004 ^ 4Q	2004 ^ Year
Recurring income from cont. ops available to common shareholders	$ 4	$ 54	$ 136	$ 68	$ 261
Recurring diluted earnings per common share	$ 0.01	$ 0.10	$ 0.26	$ 0.12	$ 0.49
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(24)	(70)	(187)	(23)	(304)
Add realized gains/losses from MTM previously recognized	136	11	45	(6)	186
Total MTM adjustments	112	(59)	(142)	(29)	(118)
Tax effect of total MTM adjustments (at 39%)	44	(23)	(55)	(11)	(46)
After tax MTM adjustments	68	(36)	(87)	(17)	(72)
Recurring income from cont. ops available to common shareholders after MTM adjust	$ 72	$ 18	$ 49	$ 50	$ 189
Recurring diluted earnings per share after MTM adj.	$ 0.14	$ 0.03	$ 0.09	$ 0.09	$ 0.35
	519,485	521,698	529,525	536,497	535,611

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Non-GAAP Reconciliation

EBITDA Reconciliation

Dollars in millions	3Q05	YTD
Net Income	**$4**	**$247**
Loss from Disc. Operations	1	2
Net Interest Expense	164	491
DD&A	190	546
Provision (benefit) for Income Taxes	(3)	169
EBITDA	**$356**	**$1,455**

Non-GAAP Reconciliation

3Q 2005 Segment Contribution

Dollars in millions

	Gas Pipes	E&P	Midstream	Power	Corp/ Other	Total
Segment Profit (Loss)	161	159	121	(226)	(10)	**205**
DD&A	67	66	49	4	3	**189**
Segment Profit before DDA	**228**	**225**	**170**	**(222)**	**(7)**	**394**
General Corporate Expense						**(43)**
Investing Income*						**13**
Other Income						**(8)**
TOTAL						**356**

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

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2005 Forecast EBITDA Reconciliation

Dollars in millions	Nov 3 Guidance	Aug 4 Guidance
Net Income	**$385 – 455**	**$350 – 480**
Income from Disc. Ops.	10 – 0	10 – 0
Net Interest	650 – 670	650 – 670
DD&A	700 – 775	700 – 775
Provision for Income Taxes	260 – 300	220 – 335
Other/Rounding	(5) – 0	(5)
EBITDA	**$2,000 - 2,200**	**$1,930 - 2,260**
MTM Adjustments	175	75
EBITDA - after MTM Adj.	**$2,175 - 2,375**	**$2,005 - 2,335**

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Non-GAAP Reconciliation

2005 Forecast Segment Contribution

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total *
Segment Profit (Loss)	575 - 600	440 - 480	630 - 645	(225) - (175)	(45) - (25)	1,375 - 1,525
DD&A	235 - 265	180 - 190	270 - 280	10 - 20	5 - 20	700 - 775
Segment Profit before DDA	810 - 865	620 - 670	900 - 925	(215) – (155)	(40) – (5)	2,075 - 2,300
Other (Primarily General Corporate Expense & Investing Income)						(70) – (100)
Rounding						(5) - 0
TOTAL						2,000 - 2,200

[1] *Segment Profit is prior to MTM adjustments*

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2005 Segment Profit - Recurring

Dollars in millions	Reported	YTD Non-Recurring	Recurring
Exploration & Production	$575 - 600	($29)	$546 - 571
Midstream	440 - 480	-	440 - 480
Gas Pipeline	630 - 645	(49)	581 - 596
Power	(225) - (175)	25	(200) - (150)
Other/Corp.	(45) - (25)	53	8 - 28
Total	**$1,375 - 1,525**	**$0**	**$1,375 - 1,525**
MTM Adjustment	175	-	175
Total After MTM Adj.	**$1,550 - 1,700**	**$0**	**$1,550 - 1,700**
Power After MTM Adj.	($50) - 0 [1]	$25	($25) - 25

[1] *Includes reported results and mark-to-market as indicated above*

Non-GAAP Reconciliation

2005 Forecast Guidance Reconciliation

Dollars in millions, except per-share amounts	Nov 3 Guidance	Aug 4 Guidance
Net Income	**$385 – 455**	**$350 – 480**
Less: Discontinued Operations	10 – 0	10 – 0
Income from Continuing Ops	**$395 – 455**	**$360 – 480**
Non-Recurring Items (Pretax)	7	23
Less / (Plus) Taxes @ Approx. 39%	0	(6)
Non-Recurring After Tax	7	17
Recurring Income from Cont. Ops	**$402 – 462**	**$377 – 497**
Recurring EPS	**$0.66 - $0.76**	**$0.62 - $0.82**
Mark-to-Market Adjustment (Pretax)	175	75
Less Taxes @ 39%	(68)	(29)
Mark-to-Market Adjust. After Tax	107	46
Inc. from Cont. Ops after MTM Adj.	**$509 - 569**	**$423 - 543**
Inc. from Cont. Ops after MTM Adj. EPS	**$0.84 - $0.94**	**$0.70 - $0.90**

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2005-07 Guidance Reconciliation

Dollars in millions	2005	2006	2007
CAP EX:			
Aug. 4 Guidance	$1,100 - 1,300	$1,525 - 1,750	$1,100 - 1,300
E&P: Incremental Drilling & costs	60	190	190
Midstream: Expansion (Opal & Blind Faith)	-	120	85
Gas Pipes: Expansions	-	10	60
Other Misc / Rounding	40 – (10)	(20)	(10)
Nov. 3 Guidance	$1,200 - 1,350	$1,825 - 2,050	$1,425 - 1,625

SEGMENT PROFIT [1]			
Aug. 4 Guidance - Reported	$1,375 - 1,660	$1,515 - 1,815	$1,640 - 2,065
E&P: Price, cost & volume Increases	140	130	180
Midstream: Margin Increases	25	-	-
" Expansions	-	-	10
Gas Pipes: Lower Expenses 25, NonRecurring/Other 10	35	-	-
" Accounting Change (30), Lower Expenses 15	-	(15)	-
Power: High Gas Prices / Weather in West	(100)	-	-
Other Misc / Rounding	75 - (60)	(110)	-
Nov. 3 Guidance - Reported	$1,550 - 1,700	$1,520 - 1,820	$1,830 - 2,255

[1] *Segment Profit After MTM Adjustment*

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2005- 07 Guidance Reconciliation

Dollars in millions	2005	2006	2007
CASH FLOW FROM OPERATIONS (CFFO):			
Aug. 4 Guidance	$1,150 - 1,450	$1,550 - 1,850	$1,650 - 1,950
E&P Seg Profit / DD&A Increases	140	140	220
Midstream Segment Profit Increase	25	-	10
Gas Pipes Segment Profit Changes	35	(15)	-
Power Change in CFFO Guidance	(25) - (75)	(25)	-
Other Increases / (Decreases)	0 - (50)	(25)	(30)
Nov. 3 Guidance	$1,325 - 1,525	$1,625 - 1,925	$1,850 - 2,150

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EPS Metrics

2005	1Q	2Q	3Q	4Q	Total
EPS	$0.34	$0.07	$0.01	-	$0.42
Recurring EPS	0.33	0.11	($0.01)	-	0.44
Rec. EPS after MTM Adj.	**0.22**	**0.16**	**0.22**	**-**	**0.60**
Average Shares (MM)	599	579	581	-	605

2004	1Q	2Q	3Q	4Q	Total
EPS	$0.02	($0.03)	$0.19	$0.13	$0.31
Recurring EPS	0.01	0.10	0.26	0.12	0.49
Rec. EPS after MTM Adj.	**0.14**	**0.03**	**0.09**	**0.09**	**0.35**
Average Shares (MM)	519	522	530	586	536

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2005 Interest Expense Guidance

Dollars in millions	2005
Interest on Long-Term Debt	$575 - 583
Amortization Discount/Premium and other Debt Expense	25 - 27
Credit Facilities: (incl. Commitment Fees plus LC Usage)	32 - 40
Interest on other Liabilities	23 - 30
Interest Expense	$655 - 680
Less: Capitalized Interest	(5) - (10)
Net Interest Expense Guidance	**$650 - 670**

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2005 Effective Tax Rates

	2005							
	First Quarter		Second Quarter		Third Quarter		YTD	
Statutory Rate	115	35%	29	35%	1	35%	145	35%
State	14	4%	1	3%	2	49%	17	4%
Foreign	(5)	-2%	5	6%	(2)	-49%	(2)	-1%
Other	5	2%	7	7%	(4)	-115%	8	2%
Tax Provision	**129**	**39%**	**42**	**51%**	**(3)**	**-80%**	**168**	**40%**

	2005	2006	2007
Effective Tax Rate Guidance[1]	**See Above**	**39%**	**39%**
Cash Tax Rate Guidance[2]	**3-5%**	**5-10%**	**5-10%**

Note 1: An additional $5-10 million income tax expense is forecast in 2006, 2007 and 2008.

Note 2: In addition to the cash tax guidance provided above, we have reached settlement with the Internal Revenue Service relating to outstanding tax issues associated with prior years. As a result of the settlements, we expect to make payments of approximately $196 million in the fourth quarter of 2005, all of which has been accrued as of September 30, 2005.

Note 3: Discontinued operations in 2005 have an immaterial impact.

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Exploration & Production

2005-2007 Hedge Update

Dollars in millions	2005 4th Qtr	2006	2007
Fixed Price:			
NYMEX			
Volume (MMcfe/d)	283	299	172
Price ($/Mcfe)	$4.49	$4.39	$4.18
Collars :			
NYMEX			
Volume (MMcfe/d)	50	65	15
Price ($/Mcfe)	$6.75 - $8.50	$6.62 - $8.42	$6.50 - $8.25
Regional			
NWPL Rockies[1]			
Volume (MMcfe/d)	50	50	50
Price ($/Mcfe)	$6.10 - $7.70	$6.05 - $7.90	$5.65 - $7.45
EPNG San Juan[1]			
Volume (MMcfe/d)			50
Price ($/Mcfe)			$5.65 - $7.45

[1] *Please note basin locations not NYMEX*

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3Q 2005 Net Realized Price Calculation

	Unhedged	3Q '05 Hedge
Market Price:		
NYMEX	$8.95 - $9.25	4.46
NYMEX collars		0.00
Basis Differential	(1.50 - 1.65)	(0.47)
Net basin market price	$7.30 - $7.75	$3.99
Net basin market price	**$7.30 - $7.75**	**$3.99**
Fuel & Shrinkage/Gathering/ Transportation	(0.80 - 1.00)	(0.80 - 1.00)
Net Price	**$6.30 - $6.95**	**$2.99 - $3.19**
Quarter Volume Totals	(qtr daily volumes - qtr daily volumes) x (92/1000)	(qtr daily hedge volumes) x (92/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

Exploration & Production

2005 4th Quarter Price Modeling

	Unhedged	2005 Hedge
Market Price:		
NYMEX	$13.00 - $13.60	$4.49
Basis Differential	(3.00 - 3.60)	(0.47)
Net basin market price	**$9.40 - $10.60**	**$4.02**
Fuel & Shrinkage/Gathering/ Transportation	(0.80 - 1.00)	(0.80 - 1.00)
Net Price	**$8.40 - $9.80**	**$3.02 - $3.22**
Year Volume Totals (Bcfe)	(total daily vols - daily hedge vols) x (92/1000)	(daily hedge volumes) x (92/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

	2005	2006	2007
Unhedged Price (NYMEX)	$8.70	$8.50	$7.00

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

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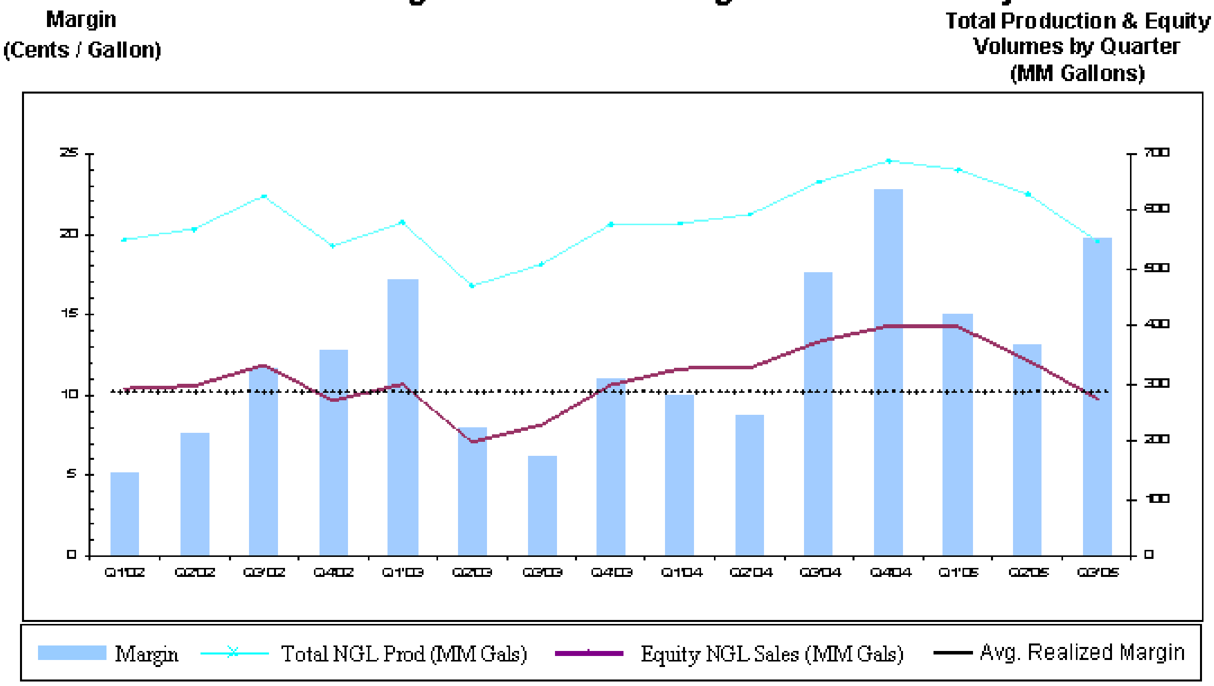
Midstream

Margins Above Average

Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Based on actual realized prices, contractual obligations, shrink, fuel, actual equity liquids percentages, etc. Average Realized Margin shown for 2000-2004.

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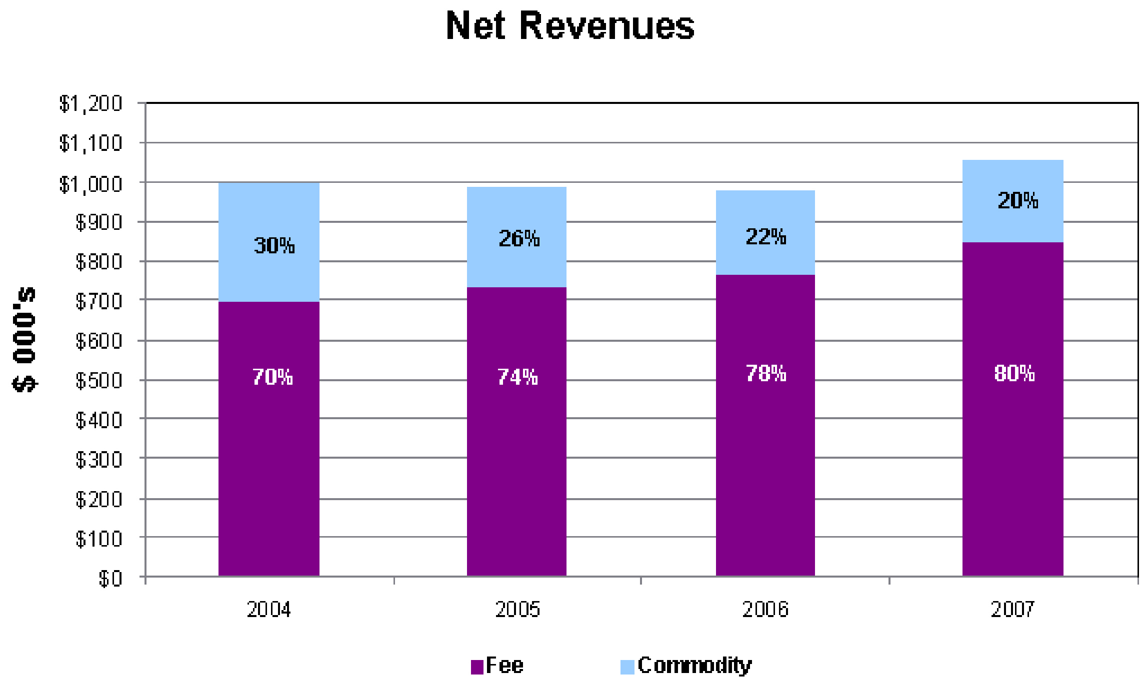
Midstream

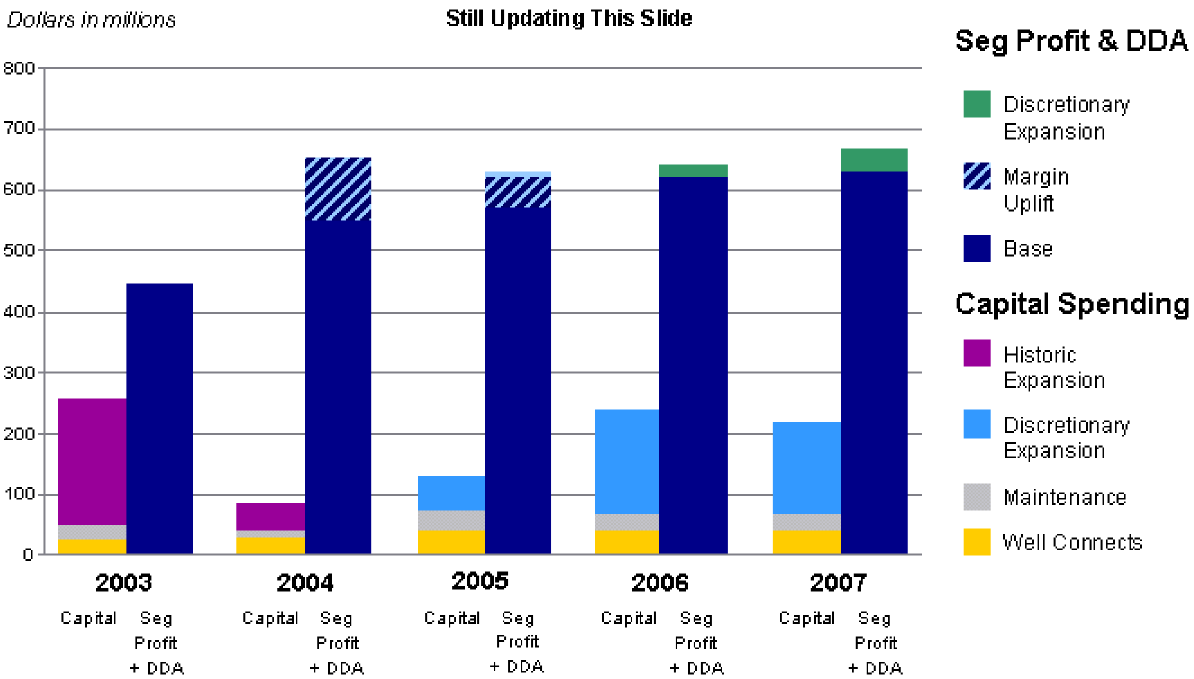
Fee-Based Bedrock of Earnings



Note: Total revenues less cost of goods sold. Reflects forecasted margins in 2006-2007 at mid-point of range.

Midstream

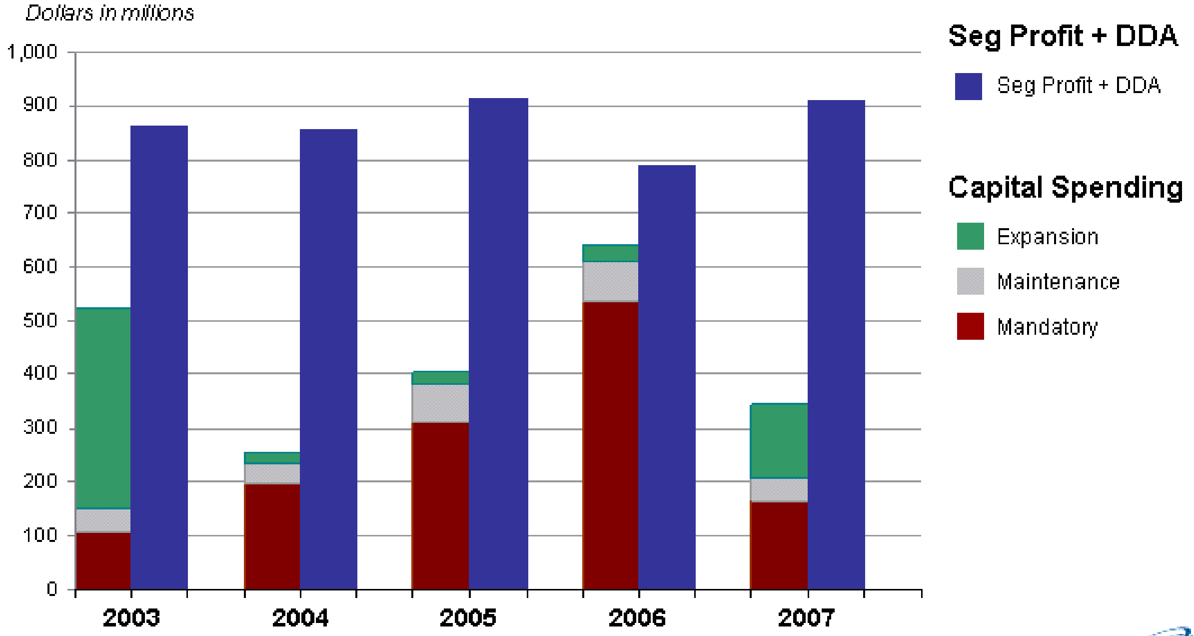
Strong Free Cash Flow



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.
- Margin uplift represents actual realized margin in excess of forecasted average margin.

Gas Pipeline

Strong Free Cash Flow



Note:
- Segment Profit is stated on a recurring basis.
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges for 2005 - 2007.

WMB Collateral Outstanding

Dollars in millions	E&P	Midstream	Power	Corp./ Other	Total
	As of 9/30/05				
Margins & Ad. Assurances[1]	$2	$0	$51	$0	$53
Prepayments	$0	$1	$24	$0	$25
Subtotal	$2	$1	$75	$0	$78
Letters of Credit	$1,145	$224	$247	$91	$1,707
Total as of 9/30/05	$1,147	$225	$322	$91	$1,785
Total as of 06/30/05	$475	$184	$357	$92	$1,108
Change	$581	$116	($49)	$1	$649

**Note: The allocation of LC's between business units as of 3/31 has been adjusted from that previously reported. Total 3/31/05 LC's reported is unchanged.*

[1] Reflects net amount of margins out less margins in.

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WMB Collateral Sensitivity

Dollars in millions

- **Margin volatility (1% chance of exceeding)**
  - Potential incremental collateral requirement

	9/30/05	6/30/05	3/31/05
– 30 days	($469)	($178)	($124)
– 180 days	($868)	($458)	($328)
– 360 days	($926)	($351)	($341)

- **Increased margin volatility results from high natural gas prices and volatility**

Assumption: The margin numbers above consist of only the forward marginable position values, starting from November 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	$0-$2	$0-5	$5-10
2006	$4-$6	$5-15	$10-15
2007	$12-15	$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).*

Williams

Types of Sales Around Tolling Deals

-Generally, from the most to least effective hedges

Type of Sale	How It Works
	Williams buys tolling rights for a certain dollar amount per kilowatt-year and:
Resale of tolling	Sells the same or similar tolling rights to another party. Example: CDWR Product D.
Heat-rate Sales	Sells call rights on energy, or fixed amounts of energy, at a price determined by a heat rate and fuel price.
Full requirements	Serves the load (demand) of an entity often at a fixed price, utilizing production from other Williams assets and/or the entity's resources. Examples: EMC and Allegheny Co-op contracts.
Capacity sales	Sells the right to claim the generation as capacity. Some energy rights are usually associated.
Forward fixed price sales	Sells fixed blocks of power at a specified price, usually w/o specifying a source. Example: CDWR ABC.

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