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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): May 4, 2006

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 May 4, 2006, The Williams Companies, Inc. ("Williams" or the "Company") issued a press release announcing its financial results for the quarter ended March 31, 2006. A copy of the press release and its accompanying consolidated statement of operations and reconciliation schedules are furnished as a part of this current report on Form 8-K as Exhibit 99.1 and is incorporated herein in its entirety by reference.

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

Item 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 May 4, 2006.

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 May 4, 2006, publicly announcing its first quarter 2006 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the May 4, 2006, public conference call and webcast.

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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: May 4, 2006

/s/ Donald R. Chappel

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

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INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
Exhibit 99.1	Copy of Williams' press release dated May 4, 2006, publicly announcing its first quarter 2006 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the May 4, 2006, public conference call and webcast.

NewsRelease

NYSE: WMB

Date: May 4, 2006

Williams Reports First Quarter 2006 Financial Results

- *Proved, Probable and Possible Reserves Increase 22% to 10.7 Tcfe*
- *Natural Gas Production Up 16% to 714 MMcfe per day*
- *Williams Continues to Deploy New Rigs in the Piceance Basin*
- *Gathering & Processing Revenues Drive Midstream to Near-Record Quarter*
- *Company Working To Complete $360 Million Transaction with Williams Partners L.P.*

Quarterly Summary Information	1Q 2006		1Q 2005	
Per share amounts are reported on a diluted basis	millions	per share	millions	per share
Income from continuing operations	$ 131.1	$ 0.22	$ 202.2	$ 0.34
Income (loss) from discontinued operations	$ 0.8	—	($1.1)	—
Net income	$ 131.9	$ 0.22	$ 201.1	$ 0.34
Recurring income from continuing operations*	$ 135.9	$ 0.23	$ 198.4	$ 0.33
After-tax mark-to-market adjustments	$ 21.1	$ 0.03	($66.0)	($0.11)
Recurring income from continuing operations — after mark-to-market adjustment*	$ 157.0	$ 0.26	$ 132.4	$ 0.22

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

TULSA, Okla. — Williams (NYSE:WMB) today announced first-quarter 2006 unaudited net income of $131.9 million, or 22 cents per share on a diluted basis, compared with net income of $201.1 million, or 34 cents per share, for first-quarter 2005.

The first quarter of 2005 benefited from $221.1 million in unrealized mark-to-market gains from the Power segment, compared with $43.0 million in unrealized mark-to-market gains in the first quarter of 2006.

Results for the first quarter of 2006 also reflect increased natural gas production and higher net realized average prices for production sold, along with increased gathering and processing revenue in Midstream. These benefits were offset by higher operating expenses.

On a basis adjusted for the effect of mark-to-market accounting, Williams earned 26 cents per share in the first quarter of 2006, up from 22 cents per share a year ago. Additional detail about the mark-to-market adjustment is included in this news release.

CEO Perspective

“We’re fully engaged in expanding our business in a way that creates additional economic value,” said

Steve Malcolm, chairman, president and chief executive officer.

"At the beginning of the year, we outlined ambitious three-year goals that include increasing segment profit by 50 percent and growing natural gas production to more than one billion cubic feet per day by 2008.

"Based on our performance in the first quarter, we're getting out of the gate on the right foot. Natural gas production is up 16 percent and we achieved near-record segment profit in Midstream.

"The results in Midstream provide an example of why we choose to have an integrated business model at Williams. Even though natural gas prices are down somewhat, Midstream benefits from the margin between these lower fuel costs and higher prices for its NGL products.

"We're also continuing to invest capital and seize opportunities to execute on our strategy of driving even greater results and returns in 2007 and 2008. Our capital investments increased more than 100 percent in the first quarter, up from $223 million a year ago to $468 million this year.

"We're focusing much of this capital on the rapid development of our natural gas reserves. Our total proved, probable and possible reserves have increased by 22 percent because of our early drilling success in the Piceance Highlands."

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 to remove 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 effect to reflect income as though mark-to-market accounting had never been applied to Power's designated hedges and other derivatives — increased 19 percent from a year ago, up from $132.4 million, or 22 cents per share in 2005, to $157.0 million, or 26 cents per share, for the first quarter of 2006.

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

Consolidated results include segment profit for Williams' primary businesses — Exploration & Production, Midstream Gas & Liquids, Gas Pipeline and Power — as well as results reported in the Other segment.

Consolidated Recurring Segment Profit Adjusted for Mark-to-Market Effect

	1Q '06 (millions)	1Q '05 (millions)
Segment profit	$ 412.3	$ 509.7
Non-recurring adjustments	($8.3)	($9.3)
Recurring segment profit	$ 404.0	$ 500.4
Reverse forward unrealized mark-to-market gains	($43.0)	($221.1)
Add realized mark-to-market gains that were previously recognized	$ 77.1	$ 113.0
Recurring segment profit after mark-to-market adjustments	$ 438.1	$ 392.3

Williams' businesses reported consolidated segment profit of $412.3 million in the first quarter of 2006, compared with $509.7 million a year ago. Results were reduced from a year ago primarily due to lower levels of forward unrealized mark-to-market gains in the Power segment.

On a basis adjusted for the effect of mark-to-market accounting, Williams had recurring consolidated segment profit of $438.1 million in the first quarter of 2006, compared with $392.3 million a year ago — an increase of 12 percent.

The first quarter of 2006 benefited from increased natural gas production and higher net realized average prices for production sold, along with increased gathering and processing revenue in Midstream.

Exploration & Production: Proved, Probable and Possible Reserves Up 22%

Exploration & Production reported first-quarter 2006 segment profit of $147.6 million, up 42 percent from a year ago when the business reported segment profit of $103.7 million.

These activities include natural gas production and development in the U.S. Rocky Mountains, San Juan Basin and Mid-Continent, and oil and natural gas operations in South America.

The year-over-year improvement reflects significant increases in both production volumes and net realized average prices for production sold, as well as a $9 million increase in unrealized gains from hedge ineffectiveness. These increases were partially offset by higher lease operating expenses and depreciation, depletion and amortization, and the absence of an $8 million gain on the sale of certain assets in 2005.

In the first quarter of 2006, average daily production from domestic and international interests was approximately 714 million cubic feet of gas equivalent (MMcfe), compared with 614 MMcfe in the first quarter of 2005 — an increase of 16 percent. The increased production was primarily from the Piceance Basin.

First-quarter 2006 average daily production solely from domestic volumes increased 16 percent from the same period a year ago, growing from 568 MMcfe to 661 MMcfe.

The business also benefited from its ability in the first quarter to realize domestic production prices averaging 18 percent higher than last year.

Williams has 21 rigs operating in the Piceance Basin of western Colorado — its cornerstone properties for production growth. The rig count includes four new-generation drilling rigs that are purpose-built for conditions in the Piceance Basin. First-quarter 2006 average daily production from the Piceance Basin was 360 MMcfe per day — a 29 percent increase over year-ago levels.

Williams also has increased the company's total proved, probable and possible reserves to an estimated 10.7 trillion cubic feet equivalent (Tcfe) — an increase of 22 percent from the previous estimate of 8.8 Tcfe. This figure includes 3.6 Tcfe of proved reserves at Dec. 31, 2005. Total reserves are comprised of international and domestic interests.

The increase in estimated reserves is based on Williams' latest analysis, particularly from its early drilling results in the relatively undeveloped areas of the Piceance Highlands.

Williams has lowered the range of segment profit it expects in 2006 from Exploration & Production.

Williams previously expected $650 million to $725 million in segment profit for Exploration & Production this year. The company now expects $525 million to $625 million in segment profit for this business. The decrease is primarily the result of lower realized and projected natural gas prices.

Midstream Gas & Liquids: Increases Guidance by $100 Million for 2006

Midstream reported first-quarter 2006 segment profit of $151.5 million, up 18 percent compared with $128.6 million a year ago.

This business provides natural gas gathering and processing services, along with NGL fractionation and storage services and olefins production.

The year-over-year improvement primarily reflects higher net revenues from its domestic gathering and processing business, as well as $9 million from the favorable resolution of an international contract dispute, partially offset by lower net olefins margins and higher costs from maintenance expenses.

The improvement in the domestic gathering and processing business was driven by significantly higher production handling revenues in the deepwater Gulf of Mexico, higher fee-based processing volumes and revenues and higher per unit NGL margins.

In first-quarter 2006, Midstream sold 333.7 million gallons of NGL equity volumes, a decrease of 16 percent compared with equity sales of 398.7 million gallons in the prior-year period. Lower volumes of equity sales were primarily the result of an increase in volumes subject to fee-based processing contracts.

Gathering volumes in the first quarter of 2006 were 296.9 trillion British thermal units (TBtu), compared with 315.5 TBtu in the 2005 period. Processing fee volumes were 191.8 TBtu in the first quarter of 2006, compared with 181.0 TBtu in the 2005 period. Revenues for both gathering and fee-based processing were higher year over year.

For the NGL equity volumes that Williams retains under certain processing contracts, the company continues to benefit from favorable margins. For the seventh quarter in a row, NGL sales margins remained above the company's five-year average.

The Cameron Meadows natural gas plant in Louisiana's Cameron Parish has been processing approximately 270 million cubic feet per day (MMcf/d) since returning to partial service in February. The facility is now scheduled to return to its full design capacity of 500 MMcf/d early in the third quarter. The plant was damaged by Hurricane Rita last September.

In Wyoming, Williams has received a permit to begin construction of the fifth cryogenic gas processing train at its Opal, Wyo., facility. The project will boost Opal's overall processing capacity from 1.1 billion cubic feet per day (Bcf/d) to more than 1.45 Bcf/d, with the ability to recover in excess of 68,000 barrels per day of NGL products.

Subsequent to the close of the quarter, Williams also reached an agreement with Williams Partners L.P. (NYSE:WPZ) for its acquisition of a 25.1 percent interest in Williams' Four Corners LLC subsidiary, which at closing will own certain gathering, processing and treating assets in the Four Corners area. The $360 million transaction — subject to standard closing conditions — is expected to close in the second quarter.

Williams has increased by $100 million the range of segment profit it expects in 2006 from Midstream. The company now expects $500 million to $600 million in segment profit from Midstream. The increase is primarily the result of higher first-quarter gathering and processing results, as well as projected NGL margins for the balance of the year. The company has entered into fixed-price sales contacts for a portion of its 2006 NGL production.

Gas Pipeline: Rate Case Filings On-Schedule

Gas Pipeline reported first-quarter 2006 segment profit of $134.7 million, down 20 percent compared with $167.4 million a year ago.

Gas Pipeline primarily delivers natural gas to markets along the Eastern Seaboard, in the Northwest, and in Florida.

The 2005 period benefited from $13 million in expense reductions related to prior periods and a $4.6 million construction fee that was associated with completing an expansion project.

The decrease in first-quarter 2006 segment profit is also attributable to higher operating costs, driven in part by higher labor costs, certain environmental remediation costs, hurricane-related damage assessments, pipeline integrity spending, and feasibility costs associated with certain business development projects.

Williams continues to prepare for new rate case filings with the Federal Energy Regulatory Commission later this year. The company expects to complete its filing for Northwest Pipeline in July and its filing for Transco in September. The new rates are expected to be effective by January and March 2007, respectively.

During the first quarter, Gulfstream reached a 23-year agreement to provide up to 345,000 dekatherms per day of firm natural gas transportation service to a Florida utility. With the agreement, all of Gulfstream's nearly 1.1 billion dekatherms of capacity is now under firm long-term contract. Williams owns a 50-percent interest in the Gulfstream Natural Gas System, L.L.C., joint venture.

Subsequent to the close of the quarter, Northwest Pipeline finalized a partnership with two other companies to develop the Pacific Connector Gas Pipeline. The proposed 223-mile project would connect a proposed liquefied natural gas terminal being developed near Coos Bay, Ore., to two pipeline systems, including Northwest. The project — tentatively expected to be completed in 2010 — is in the preliminary stages and is subject to environmental reviews and FERC approval.

Williams continues to expect $475 million to $520 million in segment profit from Gas Pipeline in 2006.

Power: On-Course to Meet 2006 Expectations

Power manages a portfolio of more than 7,000 megawatts and provides services that support Williams' natural gas businesses.

Power Recurring Segment Profit Adjusted for Mark-to-Market Effect

	1Q '06 (millions)	1Q '05 (millions)
Segment profit (loss)	($22.5)	$ 114.1
Non-recurring adjustments	$ 0.0	$ 11.4
Recurring segment profit (loss)	($22.5)	$ 125.5
Mark-to-market adjustments — net	$ 34.1	($108.1)
Recurring segment profit after mark-to-market adjustments	$ 11.6	$ 17.4

Power reported a first-quarter 2006 segment loss of $22.5 million, compared with a segment profit of $114.1 million in the same period in 2005. Results include the effect of forward non-cash unrealized mark-to-market gains and losses.

The year-over-year reduction is primarily the result of lower non-cash unrealized mark-to-market gains, partially offset by lower selling, general and administrative expenses.

On a basis adjusted for the effect of mark-to-market accounting, Power reported recurring segment profit of $11.6 million in first-quarter 2006, down 33 percent compared with $17.4 million in 2005.

The year-over-year decline in adjusted recurring segment profit reflects lower results from the natural gas portfolio, partially offset by higher results from the power portfolio and lower selling, general and administrative expenses. Lower expenses are primarily due to the positive effect of a $23.7 million gain on the sale of certain third-party receivables.

To date in 2006, Power has completed six new sales contracts that range in term and volume through December 2009. These contracts effectively reduce risk and increase cash-flow certainty.

In the first quarter, Power used approximately $142 million in cash flow from operations, largely the result of working capital changes that include the payment of margin dollars to counterparties on behalf of other Williams' entities.

On a standalone basis, excluding working capital used or received for other Williams' entities, Power generated $9 million in cash flow from operations in the first quarter. Williams continues to expect $50 million to

$150 million of standalone cash flow from operations in Power this year, excluding changes in working capital and payment of accruals associated with gas reporting agreements.

For 2006, Williams has decreased by $30 million the range of segment loss it expects from Power due to unrealized mark-to-market earnings in the first quarter. The company now expects a $105 million to $205 million segment loss from Power, absent the effect of any future unrealized mark-to-market gains or losses.

On a basis adjusted for the effect of mark-to-market accounting, Williams continues to expect Power to generate 2006 recurring segment profit of $50 million to $150 million.

Cash and Debt: Company Replacing Nearly All Secured Debt

At the close of business on March 31, 2006, Williams had total liquidity of approximately $2.6 billion. This consisted of approximately $1.1 billion in unrestricted cash and cash equivalents, approximately $184 million in other liquid investments and $1.3 billion in unused and available revolving credit facilities.

With regard to the company's revolving credit facilities, on May 1 Williams replaced an existing $1.275 billion secured facility with a new $1.5 billion unsecured facility. The new revolver removed the last secured debt from Williams' credit portfolio, with the exception of non-recourse project debt for its operations in Venezuela.

Subsequent to the close of the first quarter, Williams' liquidity was reduced by approximately $489 million for the early retirement of secured debt — including related interest — that was scheduled to mature in 2008. Williams plans to replace a portion of this liquidity on an unsecured basis later this year.

Williams' total outstanding debt at March 31, 2006, was approximately $7.4 billion. As Williams supports its planned capital investments during 2006, the company expects to conclude the year at a debt level that is comparable with year-end 2005.

Net cash provided by operating activities in the first quarter was $164.7 million, compared with $304.4 million in the same period a year ago. Net cash in the 2006 quarter was reduced by $150.1 million in margin deposits paid to third parties.

Guidance Through 2008

The forecast for earnings per share in 2006 remains at 78 cents to $1.03 on a recurring basis adjusted for the effect of mark-to-market accounting.

In 2006, Williams continues to expect $1.52 billion to $1.86 billion in consolidated segment profit on a recurring basis adjusted for the effect of mark-to-market accounting.

In 2007, Williams continues to expect consolidated segment profit of $1.83 billion to $2.25 billion on a recurring basis adjusted for the effect of mark-to-market accounting.

In 2008, Williams continues to expect consolidated segment profit of $2.02 billion to $2.58 billion on a recurring basis adjusted for the effect of mark-to-market accounting.

The company's overall capital budget continues to be $1.95 billion to $2.15 billion for 2006; $1.6 billion to $1.8 billion for 2007; and $1.5 billion to $1.75 billion for 2008. More capital may be required based on the potential development of additional projects.

Today's Analyst Call

Williams' management will discuss the company's first-quarter 2006 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 (800) 289-0496. International callers should dial (913) 981-5519. Callers should dial in at least 10 minutes prior to the start of the discussion.

Replays of the first-quarter webcast will be available for two weeks at www.williams.com.

Form 10-K

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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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.

Consolidated Statement of Operations

(UNAUDITED)

(Dollars in millions, except per-share amounts)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*
Revenues	$ 2,954.0	$ 2,871.2	$ 3,082.3	$ 3,676.1	$12,583.6	$ 3,027.5
Segment costs and expenses:						
Costs and operating expenses	2,390.3	2,491.6	2,826.2	3,162.9	10,871.0	2,588.7
Selling, general and administrative expenses	73.5	62.7	90.6	98.6	325.4	71.0
Other (income) expense — net	(1.8)	21.9	(21.4)	62.5	61.2	(22.3)
Total segment costs and expenses	2,462.0	2,576.2	2,895.4	3,324.0	11,257.6	2,637.4
Equity earnings	17.7	9.8	17.6	20.5	65.6	22.2
Loss from investments	—	(48.4)	—	(60.7)	(109.1)	—
Total segment profit	**509.7**	**256.4**	**204.5**	**311.9**	**1,282.5**	**412.3**
Reclass equity earnings	(17.7)	(9.8)	(17.6)	(20.5)	(65.6)	(22.2)
Reclass loss from investments	—	48.4	—	60.7	109.1	—
General corporate expenses	(28.0)	(35.5)	(42.8)	(48.6)	(154.9)	(31.8)
Operating income	464.0	259.5	144.1	303.5	1,171.1	358.3
Interest accrued	(164.7)	(164.6)	(166.0)	(176.4)	(671.7)	(162.8)
Interest capitalized	1.1	1.4	1.8	2.9	7.2	3.0
Investing income (loss)	31.0	(17.2)	31.1	(21.2)	23.7	46.9
Early debt retirement costs	—	—	—	(0.4)	(0.4)	(27.0)
Minority interest in income of consolidated subsidiaries	(5.2)	(4.8)	(6.8)	(8.9)	(25.7)	(7.1)
Other income (expense) — net	5.5	8.1	(1.1)	14.6	27.1	8.1
Income from continuing operations before income taxes and cumulative effect of change in accounting principle	331.7	82.4	3.1	114.1	531.3	219.4
Provision (benefit) for income taxes	129.5	41.7	(2.6)	45.3	213.9	88.3
Income from continuing operations	**202.2**	**40.7**	**5.7**	**68.8**	**317.4**	**131.1**
Income (loss) from discontinued operations	(1.1)	0.6	(1.3)	(0.3)	(2.1)	0.8
Income before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5	315.3	131.9
Cumulative effect of change in accounting principle	—	—	—	(1.7)	(1.7)	—
Net income	**$ 201.1**	**$ 41.3**	**$ 4.4**	**$ 66.8**	**$ 313.6**	**$ 131.9**
Diluted earnings per common share:						
Income from continuing operations	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**
Income (loss) from discontinued operations	—	—	—	—	—	—
Income before cumulative effect of change in accounting principle	**0.34**	**0.07**	**0.01**	**0.11**	**0.53**	**0.22**
Cumulative effect of change in accounting principle	—	—	—	—	—	—
Net income	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**
Weighted-average number of shares used in computation (thousands)	599,422	578,902	580,735	609,106	605,847	607,073
Common shares outstanding at end of period (thousands)	570,501	571,502	572,922	573,592	573,592	595,007
Market price per common share (end of period)	$ 18.81	$ 19.00	$ 25.05	$ 23.17	$ 23.17	$ 21.39
Common dividends per share	$ 0.05	$ 0.05	$ 0.075	$ 0.075	$ 0.25	$ 0.075

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 Utility Statement:

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

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

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

(UNAUDITED)

(Dollars in millions, except per-share amounts)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*
Income from continuing operations available to common stockholders	$ 202.2	$ 40.7	$ 5.7	$ 68.8	$ 317.4	$ 131.1
Income from continuing operations — diluted earnings (loss) per common share	$ 0.34	$ 0.07	$ 0.01	$ 0.11	$ 0.53	$ 0.22
Nonrecurring items:						
Exploration & Production						
Gain on sale of E&P properties	(7.9)	—	(21.7)	—	(29.6)	—
Loss provision related to an ownership dispute	0.3	—	—	—	0.3	—
Total Exploration & Production nonrecurring items	(7.6)	—	(21.7)	—	(29.3)	—
Gas Pipeline						
Prior period liability corrections — TGPL	(13.1)	(4.6)	—	—	(17.7)	—
Prior period pension adjustment — TGPL	—	(17.1)	—	—	(17.1)	—
Income from favorable ruling on FERC appeal (1999 Fuel Tracker)	—	—	(14.2)	—	(14.2)	—
Prior period inventory corrections — TGPL	—	—	—	27.5	27.5	—
Accrual of contingent refund obligation — TGPL	—	—	—	9.8	9.8	—
Reversal of litigation contigency due to favorable ruling — TGPL	—	—	—	—	—	(2.0)
Total Gas Pipeline nonrecurring items	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)
Midstream Gas & Liquids						
Settlement of an international contract dispute	—	—	—	—	—	(6.3)
Total Midstream Gas & Liquids nonrecurring items	—	—	—	—	—	(6.3)
Power						
Accrual for a regulatory settlement (1)	4.6	—	—	—	4.6	—
Accrual for litigation contingencies (1)	—	13.1	0.4	68.7	82.2	—
Impairment of Aux Sable	—	—	—	23.0	23.0	—
Prior period correction	6.8	—	—	—	6.8	—
Total Power nonrecurring items	11.4	13.1	0.4	91.7	116.6	—
Other						
Impairment of Longhorn	—	49.1	—	38.1	87.2	—
Write-off of capitalized project development costs	—	4.0	—	—	4.0	—
Gain on sale of real property	—	—	—	(9.0)	(9.0)	—
Total Other nonrecurring items	—	53.1	—	29.1	82.2	—
Nonrecurring items included in segment profit (loss)	(9.3)	44.5	(35.5)	158.1	157.8	(8.3)
Nonrecurring items below segment profit (loss)						
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)	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	—
Legal fees associated with shareholder litigation (General corporate expenses — Corporate)	—	—	—	9.4	9.4	1.2
Reversal of interest accrual related to reversal of litigation contingency noted above (Other interest expense — Gas Pipeline — TGPL)	—	—	—	—	—	(5.0)
Premium and fees related to convertible debt conversion — (Other income (expense) — net — Corporate)	—	—	—	—	—	27.0
Gain on sale of Algar/Triangulo shares (Investing income / loss — Other)	—	—	—	—	—	(6.7)
	2.7	(8.6)	18.8	9.4	22.3	16.5
Total nonrecurring items	(6.6)	35.9	(16.7)	167.5	180.1	8.2
Tax effect for above items (1)	(2.8)	10.7	(6.4)	48.0	49.5	3.4
Adjustment for nonrecurring excess deferred tax benefit	—	—	—	(20.2)	(20.2)	—
Recurring income (loss) from continuing operations available to common stockholders	$ 198.4	$ 65.9	($4.6)	$ 168.1	$ 427.8	$ 135.9
Recurring diluted earnings (loss) per common share	$ 0.33	$ 0.11	($0.01)	$ 0.28	$ 0.72	$ 0.23
Weighted-average shares — diluted (thousands)	599,422	578,902	580,735	609,106	605,847	607,073

(1) No tax effect on $.6 million of the accrual for a regulatory settlement in 1st quarter 2005 and $8 million and $42 million of the accrual for litigation contingencies in 2nd quarter 2005 and 4th quarter 2005, respectively. The tax rate applied to Midstream's international contract dispute settlement in 1st quarter 2006 is 34%.

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

Adjustment to remove MTM effect

Dollars in millions except for per share amounts	2006					2005				
	1Q	2Q	3Q	4Q	Year	1Q	2Q	3Q	4Q	Year
Recurring income from cont. ops available to common shareholders	**$ 136**				**$ 136**	**$ 198**	**$ 67**	**$ (5)**	**$ 168**	**$ 428**
Recurring diluted earnings per common share	**$ 0.23**				**$ 0.23**	**$ 0.33**	**$ 0.11**	**$ (0.01)**	**$ 0.28**	**$ 0.72**
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(43)				(43)	(221)	(22)	141	(70)	(172)
Add realized gains/losses from MTM previously recognized	77				77	113	77	72	48	310
Total MTM adjustments	34				34	(108)	55	213	(22)	138
Tax effect of total MTM adjustments (at 39%)	13				13	(42)	21	83	(8)	53
After tax MTM adjustments	21				21	(66)	34	130	(14)	85
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 157**				**$ 157**	**$ 132**	**$ 101**	**$ 125**	**$ 154**	**$ 513**
Recurring diluted earnings per share after MTM adj.	**$ 0.26**				**$ 0.26**	**$ 0.22**	**$ 0.17**	**$ 0.22**	**$ 0.26**	**$ 0.86**
weighted average shares — diluted (thousands)	607,073				607,073	599,422	578,902	580,735	609,106	605,847

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

Exhibit 99.2

Williams 2006
1st Quarter Earnings

May 4, 2006

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

Oil and Gas Reserves Disclaimer

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves. We use certain terms in this presentation, such as "probable" 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 Web site at www.williams.com.

Overview

Steve Malcolm
Chairman, President & CEO

Headlines

- Key earnings measure jumps 19% on 1Q performance
- Development and step-outs boost proved, probable and possible reserves 22%
- Activity yields 16% increase over 1Q05 in natural gas production
- Continued drilling ramp-up designed to deliver more reserves, production growth
- Integrated model balances volatile commodity markets
- Company working to complete $360 million transaction with WPZ
- Financings contribute to stronger balance sheet

Key Operations Accomplishments

- Increased 1Q natural gas production nearly 100 MMcfe/d
- Ramp-up in Piceance development continues
  - Deployed 4 new H&P rigs to develop Piceance Basin production
  - Kicked off 2006 drilling in Piceance Highlands
  - Additional 10-acre spacing OK'd
- Firmed up plan for new NGL take-away capacity from Wyoming
- Entered into sales hedge for some NGL production
- Completing steps to put new rates into effect for Transco, Northwest
- Filled Gulfstream mainline via 23-year agreement
- Received strong demand for expansions on our interstate gas pipelines
- Executed additional risk-reducing deals in Power

Financial Results

Don Chappel
Chief Financial Officer

Financial Results

Dollars in millions (except per share amounts)	1st Quarter 2006	1st Quarter 2005
Income from Continuing Operations	$131	$202
Income (Loss) from Discontinued Operations	1	(1)
Net Income	$132	$201
Net Income/Share	$0.22	$0.34
Recurring Income from Continuing Operations /Share	$0.23	$0.33
Recurring Income from Continuing Operations After MTM Adjustments/Share	**$0.26**	**$0.22**

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

Consolidated

Recurring Income from Continuing Operations

Dollars in millions (except per share amounts)	1st Quarter 2006	2005
Income from Continuing Operations	$131	$202
Nonrecurring Items		
Debt Retirement Expense	27	-
Regulatory & Litigation Contingencies/Settlements	(7)	4
(Income)/expense related to prior periods	(6)	(6)
Gain on sale of assets	(7)	(8)
Other - Net	1	3
Total Nonrecurring items before taxes	8	(7)
Tax effect of adjustments	(3)	3
Recurring Inc. from Continuing Ops. Avail. to Com.	$136	$198
Recurring Income from Cont. Ops./Share	$0.23	$0.33

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

Recurring Income from Cont. Ops. after MTM Adjustment

Dollars in millions (except per share amounts)	1st Quarter 2006	2005
Recurring Income from Continuing Ops. Avail. to Common	$136	$198
Recurring Diluted Earnings per Common Share	$0.23	$0.33
Mark-to-Market (MTM) adjustments for Power:		
Reverse forward unrealized MTM (gains) losses	(43)	(221)
Add realized gains from MTM previously recognized	77	113
Total MTM adjustments	34	(108)
Tax Effect of Total MTM Adjustments	(13)	42
After-Tax MTM Adjustments	21	(66)
Recurring Income from Cont. Ops. Avail. to Common Shareholders after MTM Adjustments	$157	$132
Recurring Diluted Earnings Per Share after MTM adjustments	$0.26	$0.22

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

First Quarter Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production (see slide 44)	$148	$104	$148	$96
Midstream Gas & Liquids (see slide 51)	151	129	145	129
Gas Pipeline (see slide 57)	135	167	133	154
Power (see slide 62)	(23)	114	(23)	125
Other	1	(4)	1	(4)
Segment Profit	**$412**	**$510**	**$404**	**$500**
MTM Adjustments - Power			34	(108)
Segment Profit after MTM Adjustments			**$438**	**$392**
Memo:				
Power after MTM Adjustments			**$11**	**$17**

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

2006 Cash Information

Dollars in millions

	1st Qtr
Beginning Unrestricted Cash	**$ 1,597**
Cash flow from Continuing Operations	165 [1]
Debt Retirements	(64)
Capital Expenditures	(468)
Dividends	(45)
Other-Net	(70)
Change in Cash and Cash equivalents	$ (482)
Ending Unrestricted Cash at 03/31/06	**$ 1,115**
Restricted Cash at 03/31/06 (not included above)	$ 118

[1] *Cash flow from continuing operations was reduced by the return of $192 million of margin deposits to counterparties*

Liquidity at March 31, 2006

Dollars in millions

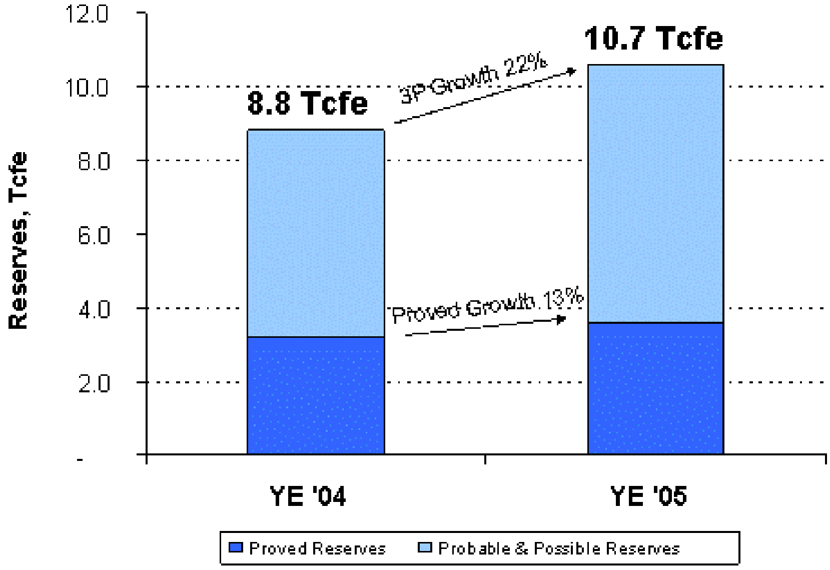
Cash and cash equivalents		$ 1,115
Other current securities		184
Less:		
Subsidiary and International cash & cash equivalents	$284	
Customer margin deposits payable[1]	129	(413)
Available unrestricted cash		886
Available revolver capacity		1,349
Total Liquidity		$ 2,235

[1] *Customer margin deposits payable was reduced by the return of $192 million of margin deposits to counterparties*

Exploration & Production

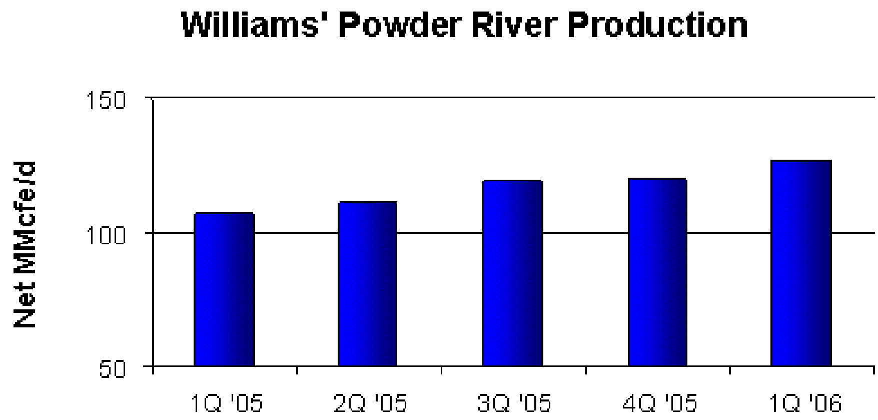
Ralph Hill
President

Total 3P Reserves Grow by 22%



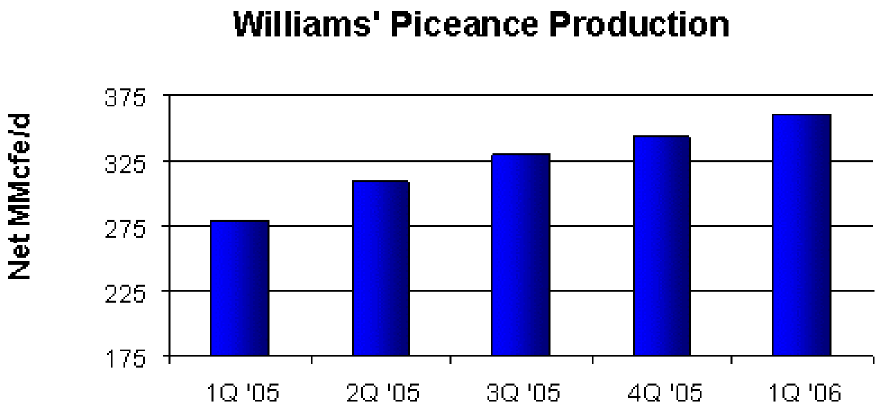
Powder River

- Up 17 MMcfed or 16% over a year ago
- Big George production is driving basin growth



Piceance Production Growth

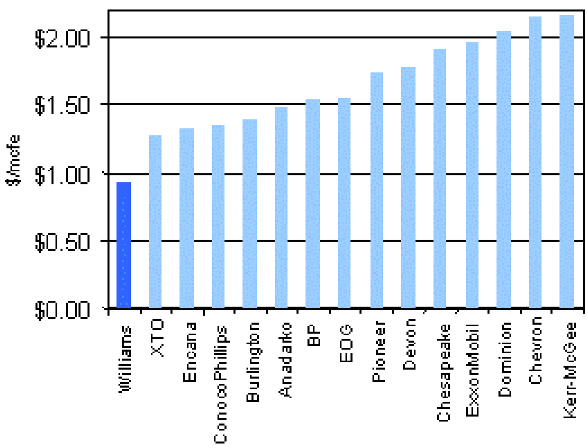
- Up 81 MMcfed or 29% over a year ago
- 21 rigs currently operating compared to 13 a year ago
- 6 additional H&P FlexRigs to be received



Low Cost Industry Leader

- Industry leader in 3-year average F&D cost of $0.92/Mcfe
- Top quartile in 2005 production cost per Mcfe
- Top quartile Reserves Replacement Rate of 277%

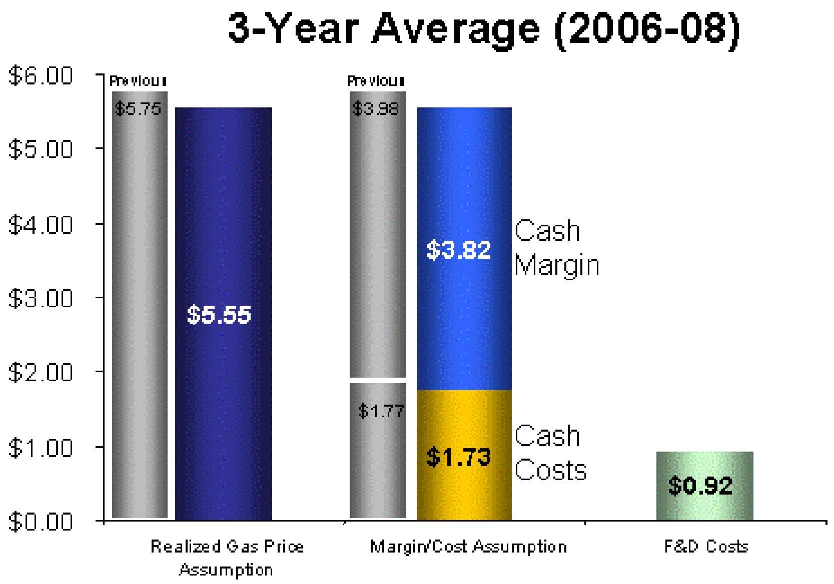
3-yr Avg ('03-'05) F&D Cost *



Graph represents top 15 E&P companies ranked by US Natural Gas Reserves

* Source: EvaluateEnergy.com

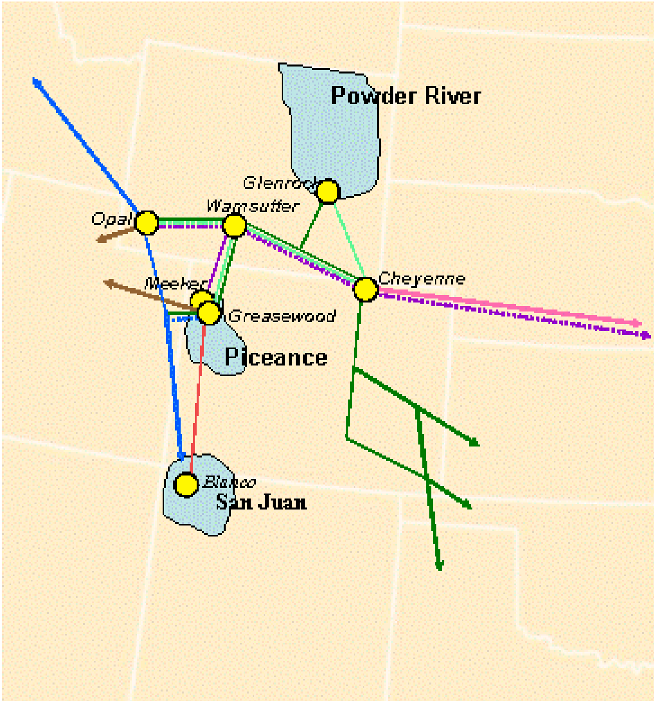
Cash Margin Analysis



Reflective of core basins

- *$5.55 is after hedging and includes average basin market price of $6.75 before hedging*
- *Cash costs include LOE, G&A, taxes and gathering*
- *F&D costs include acquisition and development expenditures/proved reserves ('03-'05 average)*

Rockies Producer Not Rockies Price Taker



Pipes Used to Move Williams Gas

- CIG
- NWPL
- Questar
- Rockies Express
- Trailblazer
- TransColorado
- WIC

Firm Access Under Contract

North to Wamsutter	200
East to Mid-continent	209
South to San Juan	285
2008 – 2009 adds	
West to Opal	150
East to Appalachia (REX)	200

2006-08 Consolidated Outlook

Don Chappel
Chief Financial Officer

2006 Forecast Guidance

Dollars in millions, except per-share amounts	May 4 Guidance	Feb 28 Guidance
Segment profit before MTM adjustment	$1,273 - $1,613	$1,240 - $1,580
Net Interest Expense	(665) - (705)	(665) - (705)
Other (Primarily General Corp. Costs)	(85) - (120)	(90) - (120)
Pretax Income	523 - 788	485 - 755
Provision for Income Tax	(210) - (320)	(200) - (315)
Income from Continuing Ops	313 - 468	285 - 440
Income/(Loss) from Discontinued Ops	(5) - 0	(5) - 0
Net Income	$308 - 468	$280 - 440
Diluted EPS	$0.50 - $0.77	$0.46 - $0.72
Recurring Income from Cont. Ops	$318 - $473	$303 - $458
Diluted EPS – Recurring	$0.52 - $0.78	$0.50 - $0.75
Diluted EPS – Recurring After MTM Adj. [1]	**$0.78 - $1.03**	**$0.78 - $1.03**

[1] *Includes MTM adjustment of $255 million (pretax) in May 4 guidance and $280 million (pretax) in Feb 28 guidance*
Note: Fully diluted shares of 610 million

2006-08 Segment Profit

Dollars in millions	**2006**	**2007**	**2008**
Exploration & Production	$525 - 625 *650 - 725*	$775 - 900	$950 - 1,100
Midstream	500 - 600 *400 - 500*	410 - 530	440 - 580
Gas Pipeline	475 - 520	585 - 655	590 - 665
Power [1]	(205) - (105) *(235) - (135)*	(165) - (15) *(160) - (10)*	(165) - (15) *(150) - 0*
Other / Corp. / Rounding	(22) - (27) *(55) - (35)*	10 - (30)	(15) - 35
Total Reported Before MTM Adj.	$1,273 - 1,613 *$1,240 - 1,580*	$1,615 - 2,040 *$1,620 - 2,045*	$1,800 - 2,365 *$1,815 - 2,380*
MTM Adjustment	255 *280*	215 *210*	215 *200*
Total Reported After MTM Adj.	$1,528 - 1,868 *$1,520 - 1,860*	$1,830 - 2,255	$2,015 - 2,580
Nonrecurring Items	(8) *-*	-	-
Total Recurring After MTM Adj.	**$1,520 - 1,860**	**$1,830 - 2,255**	**$2,015 - 2,580**

[1] Power's segment profit guidance after MTM adjustments is unchanged at 50 -150 in 2006, 50 - 200 in 2007, and 50 - 200 in 2008

Note: If guidance has changed, previous guidance from 2/28/06 is shown in italics directly below

2006-08 Capital Expenditures

Dollars in millions	2006	2007	2008
Exploration & Prod.	$950 - 1,050	$950 - 1,050	$1,000 - 1,150
Midstream	280 - 300	230 - 270	70 - 90
Gas Pipeline	710 - 785	390 - 490	410 - 510
Power	-	-	-
Other/Corporate	10 - 30	10 - 30	10 - 30
Total	$1,950 - 2,150	$1,600 - 1,800	$1,500 - 1,750

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

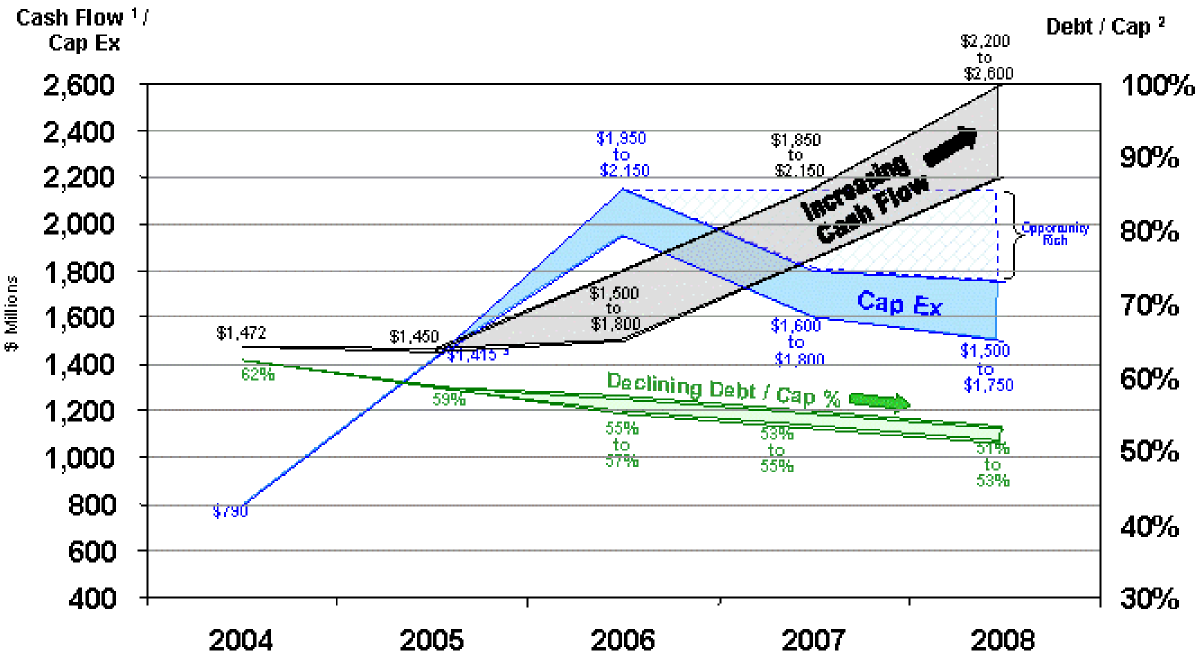
2006-08 Outlook

Dollars in millions	2006	2007	2008
Segment Profit			
Reported After MTM Adj.	$1,528 - 1,868 *$1,520 - 1,860*	$ 1,830 - 2,255	$2,015 - 2,580
Recurring After MTM Adj.	1,520 - 1,860	1,830 - 2,255	2,015 - 2,580
DD&A	790 - 890	900 - 1,000	1,000 - 1,100
Cash Flow from Ops.[1]	1,500 - 1,800 *1,625 - 1,925*	1,850 - 2,150	2,200 - 2,600
Capital Expenditures	1,950 - 2,150	1,600 - 1,800	1,500 - 1,750
Operating Free Cash Flow [2]	(450) - (350) *(325) - (225)*	250 - 350	700 - 850

[1] Cash flow from continuing operations. Reduction from 2006 resulted from margin deposits returned to counterparties.
[2] Operating free cash flow is defined as cash flow from continuing operations less capital expenditures, before dividend or principal payments

Note: If guidance has changed, previous guidance from 2/28/06 is shown in italics directly below

Strong Operating Cash Flow Growth & Increasing Investment Opportunities



1 *Cash Flow from Continuing Operations (CFFO)*
2 *Debt to Capitalization = Total Debt / (Total Debt + Equity)*
3 *Includes Purchases of Long-term Investments*

Financing Activities to Date

- Increased Equity
  - Early conversion of $220 million of 5.5% Junior Subordinated Convertible Debentures reduced debt and increased equity
- Removed Secured Debt
  - Retired $486MM Williams Production RMT term loan
  - Replaced $1.275B secured revolver with $1.5B unsecured revolver credit facility
- Issued $200MM in Senior Unsecured Notes at Transco
- Retired $64 million of debt at maturity

Planned Future Financing Transactions

- Senior Unsecured WMB offering to refinance a portion of recently retired Williams Production RMT term loan
- Debt & Equity offering at WPZ to fund Four Corners acquisition
- Financing at NWP to fund capital projects

This information shall not constitute an offer to sell or solicitation of an offer to buy any securities.

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

Summary

Steve Malcolm
Chairman, President & CEO

Headlines

- Key earnings measure jumps 19% on 1Q performance
- Development and step-outs boost proved, probable and possible reserves 22%
- Activity yields 16% increase over 1Q05 in natural gas production
- Continued drilling ramp-up designed to deliver more reserves, production growth
- Integrated model balances volatile commodity markets
- Company working to complete $360 million transaction with WPZ
- Financings contribute to stronger balance sheet

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

Non-GAAP Reconciliation Schedule

Williams

Reconciliation of Segment Profit to Recurring Segment Profit
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr
Segment profit (loss):						
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0
Total segment profit	$ 509.7	$ 256.4	$ 204.5	$ 311.9	$ 1,282.5	$ 412.3
Nonrecurring adjustments:						
Exploration & Production	$ (7.6)	$ -	$ (21.7)	$ -	$ (29.3)	$ -
Gas Pipeline	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)
Midstream Gas & Liquids	-	-	-	-	-	(6.3)
Power	11.4	13.1	0.4	91.7	116.6	-
Other	-	53.1	-	29.1	82.2	-
Total segment nonrecurring adjustments	$ (9.3)	$ 44.5	$ (35.5)	$ 158.1	$ 157.8	$ (8.3)
Recurring segment profit (loss):						
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0
Total recurring segment profit	$ 500.4	$ 300.9	$ 169.0	$ 470.0	$ 1,440.3	$ 404.0

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

Non-GAAP Reconciliation Schedule – EPS after MTM adjustment

Dollars in millions except per share amounts

	2006				
	1Q	2Q	3Q	4Q	Year
Recurring income from cont ops available to common shareholders	$ 136				$ 136
Recurring diluted earnings per common share	$ 0.23				$ 0.23
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(43)				(43)
Add realized gains/losses from MTM previously recognized	77				77
Total MTM adjustments	34				34
Tax effect of total MTM adjustments	13				13
After tax MTM adjustments	21				21
Recurring income from cont ops available to common shareholders after MTM adjust	$ 157				$ 157
Recurring diluted earnings per share after MTM adj.	$ 0.26				$ 0.26
Weighted average shares - diluted (thousands)	607,073				607,073

	2005				
	1Q	2Q	3Q	4Q	Year
Recurring income from cont ops available to common shareholders	$ 198	$ 67	$ (5)	$ 168	$ 428
Recurring diluted earnings per common share	$ 0.33	$ 0.11	$ (0.01)	$ 0.28	$ 0.72
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(221)	(22)	141	(70)	(172)
Add realized gains/losses from MTM previously recognized	113	77	72	48	310
Total MTM adjustments	(108)	55	213	(22)	138
Tax effect of total MTM adjustments	(42)	21	83	(8)	53
After tax MTM adjustments	(66)	34	130	(14)	85
Recurring income from cont ops available to common shareholders after MTM adjust	$ 132	$ 101	$ 125	$ 154	$ 513
Recurring diluted earnings per share after MTM adj.	$ 0.22	$ 0.17	$ 0.22	$ 0.26	$ 0.86
Weighted average shares - diluted (thousands)	599,422	578,902	580,735	609,106	605,847

EBITDA Reconciliation

Dollars in millions	**1Q06**
Net Income	$ 132
(Gain)/Loss from Discontinued Operations	(1)
Net Interest Expense	160
DD&A	197
Provision for Income Taxes	88
EBITDA	$ 576

1Q 2006 Segment Contribution

Dollars in Millions

	E&P	Gas Pipeline	Midstream	Power	Corp/ Other	Total
Segment Profit (Loss)	$148	$135	$151	$ (23)	$ 1	**$412**
DD&A	73	69	49	3	3	**197**
Segment Profit before DDA	**$221**	**$204**	**$200**	**$ (20)**	**$ 4**	**$609**
General Corporate Expense						**(32)**
Investing Income*						**25**
Other Income						**(26)**
TOTAL						**$576**

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

2006 Forecast EBITDA Reconciliation

Dollars in millions	**May 4 Guidance**	**Feb 28 Guidance**
Net Income	**$308 - 468**	**$280 - 440**
Loss from Disc. Ops.	5 - 0	5 - 0
Net Interest	665 - 705	665 - 705
DD&A	790 - 890	790 - 890
Provision for Income Taxes	210 - 320	200 - 315
Other/Rounding	(3) - (8)	10 - 0
EBITDA	**$1,975 - 2,375**	**$1,950 - 2,350**
MTM Adjustments	255	280
EBITDA - After MTM Adj.	**$2,230 - 2,630**	**$2,230 - 2,630**

2006 Forecast Segment Contribution

Williams

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total
Segment Profit (Loss)	\$525 - 625	\$500 - 600	\$475 - 520	\$(205) - (105)	\$(22) - (27)	\$1,273 - 1,613
DD&A	335 - 375	190 - 200	280 - 300	10 - 20	(25) – (5)	790 - 890
Segment Profit Before DDA	\$860 - 1,000	\$690 - 800	\$755 - 820	\$(195) - (85)	\$(47) – (32)	\$2,063 - 2,503
Other (Primarily General Corporate Expense & Investing Income)						(85) - (120)
Rounding						(3) - (8)
TOTAL						\$1,975 - 2,375

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

2006 Forecast Guidance Contribution

Dollars in millions, except per-share amounts	May 4 Guidance	Feb 28 Guidance
Net Income	**$308 - 468**	**$280 - 440**
Less: Discontinued Operations (Loss)	(5) – 0	(5) – 0
Income from Continuing Ops	**$313 - 468**	**$285 - 440**
Non-Recurring Items (Pretax)	8	30
Less Taxes @ Approx. 39%	3	12
Non-Recurring After Tax	5	18
Recurring Income from Cont. Ops	**$318 - 473**	**$303 - 458**
Recurring EPS	**$0.52 - $0.78**	**$0.50 - $0.75**
Mark-to-Market Adjustment (Pretax)	255	280
Less Taxes @ 39%	(99)	(109)
Mark-to-Market Adjust. After Tax	156	171
Inc. from Cont. Ops after MTM Adj.	**$474 - 629**	**$474 -629**
Inc. from Cont. Ops after MTM Adj. EPS	**$0.78 - $1.03**	**$0.78 - $1.03**

Appendix

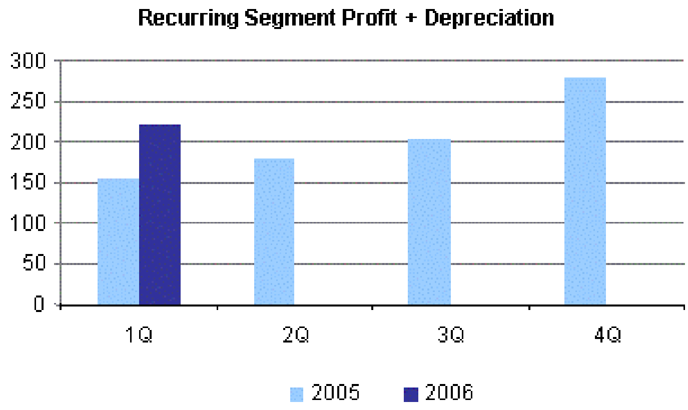
Segment Profit

Dollars in millions	1st Quarter 2006	1st Quarter 2005
Segment Profit	$148	$104
Nonrecurring		
Gain on sales of assets	-	(8)
Recurring segment profit	$148	$96

- 1Q05 to 1Q06 financial highlights include:
  - 16% volume production growth
  - 54% recurring segment profit growth
  - $85 million negative hedge impact in 1Q06 compared to $36 million in 1Q05

2006 Accomplishments

- 1Q06 total production up 16%, 100 MMcfed, since 1Q05
- 4 H&P rigs drilling
- Additional Piceance 10-acre spacing approved in April for 11,200 acres
- Piceance Highlands 2006 drilling program begins
- Ft. Worth facilities connected and flowing



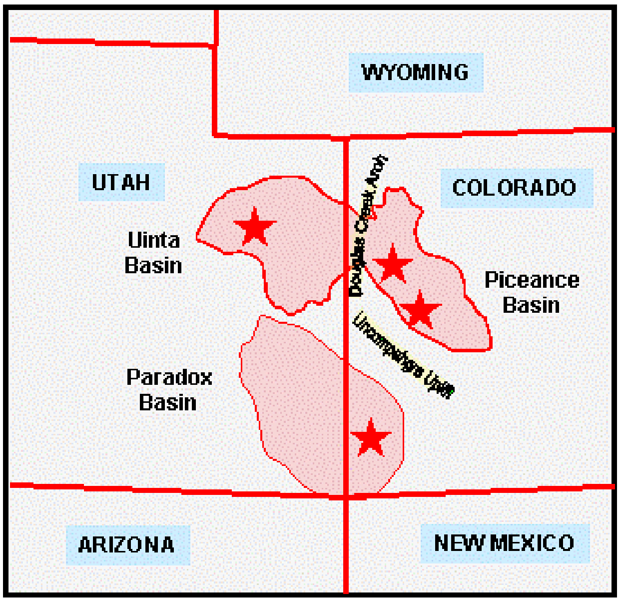
2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$525 – 625 *650 - 725*	$775 - 900	$950 - 1,100
Annual DD&A	335 - 375	425 - 475	475 - 525
Segment Profit + DD&A	$860 – 1,000 *985 – 1,100*	$1,200 - 1,375	$1,425 - 1,625
Capital Spending	$950 - 1,050	$950 - 1,050	$1,000 - 1,150
Production (MMcfe/d)	750 - 825	875 - 975	950 - 1,100
Unhedged Price Assumption ($/Mcf)	**2Q-4Q**		
Average San Juan/Rockies Price	$6.09 *$7.32*	$6.09	$6.10
Average Mid-continent Price	$6.75	$6.75	$6.77
NYMEX	$7.50 *$8.50*	$7.00	$7.00

Note: 2006-08 hedge information included in Appendix.

Note: If guidance has changed, previous guidance from 2/28/06 is shown in italics directly below.

New E&P Opportunities



- Piceance Basin: Shale Ridge Prospect (Dakota Sandstone play)
  - Leased 13,904 gross/net acres
  - 100% WI; 87.5% NRI
  - 10-year lease term
- Piceance Basin: Pending Williams Fork Project
  - 2006 drill-to-earn commitment
  - 11,000 net acres
- Uinta Basin: Sterling Hollow Prospect (Mesaverde tight gas sands play)
  - Leased 39,911 contiguous gross/net acres
  - 100% WI; 87.5% NRI
  - 10-year lease term
- Paradox Basin: Resource Play (Ismay Group shales and tight gas sandstones)
  - Leased 30,608 gross/net acres
  - 100% WI; 87.5% NRI
  - 5-year and 10-year terms on leases

US Natural Gas Reserves Rankings

	Company	Bcf 2004	Bcf 2005	2005 Reserves Repl. Rate
1	BP	14,081	15,382	72%
2	ExxonMobil	12,329	13,692	112%
3	ConocoPhillips	7,578	7,586	230%
4	Chesapeake	4,374	6,901	659%
5	Anadarko	6,093	6,578	151%
6	XTO	4,715	6,086	463%
7	Burlington	5,076	5,275	146%
8	EnCana	4,636	5,267	400%
9	Devon	4,936	5,164	115%
10	Dominion	4,814	4,856	197%
11	Chevron	3,704	4,428	175%
12	Kerr-McGee	3,772	3,633	-107%
13	Williams	2,986	3,382	277%
14	EOG	2,383	2,948	204%
15	Pioneer	3,000	2,751	48%
16	Shell	2,823	2,680	78%
17	Apache	2,406	2,566	209%
18	Occidental	2,101	2,338	184%
19	El Paso	1,724	1,831	186%
20	Noble	520	1,641	644%

Source: EvaluateEnergy.com

Williams is a Leader in US Gas Production Growth through the Drill Bit

Williams

Top 20 U.S. Gas Producers
(sorted by 2005 MMcfd)

	Company	MMcfd 2004	MMcfd 2005	Percent change
1	BP	2,749	2,546	-7.4%
2	ExxonMobil	1,947	1,739	-10.7%
3	Chevron	1,873	1,634	-12.8%
4	Devon	1,645	1,521	-7.6%
5	ConocoPhillips	1,388	1,381	-0.5%
6	Chesapeake	880	1,157	31.5%
7	Shell	1,332	1,150	-13.7%
8	Anadarko	1,363	1,134	-16.8%
9	EnCana	869	1,096	26.1%
10	XTO	835	1,033	23.8%
11	Kerr-McGee	836	962	15.1%
12	Burlington	908	950	4.6%
13	Dominion	852	753	-11.6%
14	EOG	631	718	13.8%
15	Williams	519	612	18.0%
16	Apache	647	597	-7.6%
17	Marathon	631	578	-8.4%
18	El Paso	650	566	-12.9%
19	Occidental	507	553	9.1%
20	Newfield	540	523	-3.1%
	TOTAL	21,602	21,205	-1.8%

Source: Evaluate Energy.com

Top 20 U.S. Gas Producers
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	TOTAL	21,602	21,205	-1.8%

2006-08 Hedge Update

Dollars in millions

	2Q-4Q 2006	2007	2008
Fixed Price at the basin:			
Volume (MMcf/d)	301	172	73
Average Price ($/Mcf)	$3.82	$3.90	$3.96
NYMEX Collars:			
Volume (MMcf/d)	65	15	-
Average Price ($/Mcf)	$6.62 - $8.42	$6.50 - $8.25	
At the Basin Collars:[1]			
NWPL Rockies			
Volume (MMcf/d)	50	50	75
Price ($/Mcf)	$6.05 - $7.90	$5.65 - $7.45	$6.02 - $9.52
EPNG San Juan			
Volume (MMcf/d)	-	130	25
Average Price ($/Mcf)		$5.98 - $9.63	$6.20 - 9.57
Mid-Continent			
Volume (MMcf/d)	-	70	-
Price ($/Mcf)		$6.78 - $10.89	

[1] *Please note basin locations are not NYMEX*

Segment Profit

Dollars in millions	1st Quarter 2006	1st Quarter 2005
Segment Profit	$151	$129
Nonrecurring		
International Contract Settlement	(6)	
Recurring segment profit	$145	$129

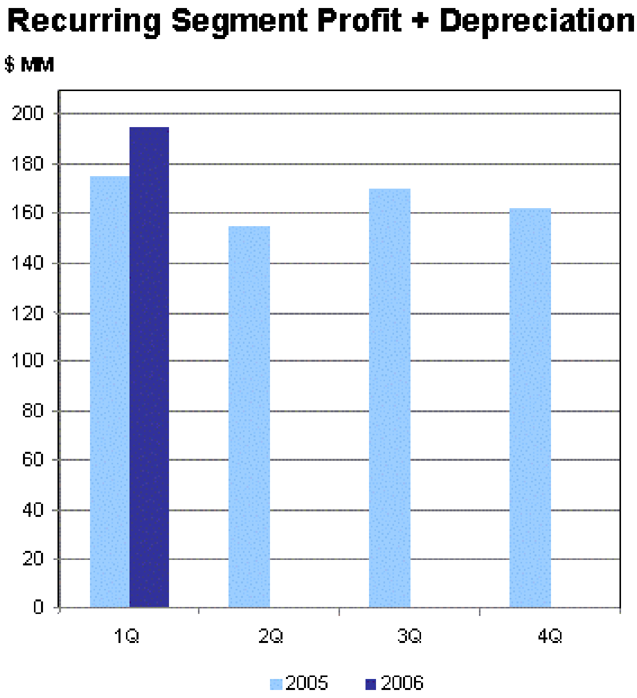
- **1Q06 to 1Q05 financial highlights include:**

  Near record quarter (4Q04 recurring was $151)

  - Higher deepwater production handling revenues
  - Higher revenues from increased G&P fees
  - Slightly exceeded strong 1Q05 net NGL margins
  - Lower olefins margins
  - Higher G&P operating expenses

2006 Accomplishments

- Increased NGL production
- Cameron Meadows back-on line
- Entering into forward sale of NGL's
- Discovery Emergency Open Season volumes
- New Deepwater development
- Progress on Overland Pass project
- Entered into agreement with WPZ for 25.1% interest in Four Corners



2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$500 - 600 *400 – 500*	$410 - 530	$440 – 580
Annual DD&A	190 - 200	200 - 210	210 – 220
Segment Profit + DD&A	$690 - 800 *590 – 700*	$610 - 740	$650 – 800
Capital Spending	$280 - 300	$230 - 270	$70 – 90

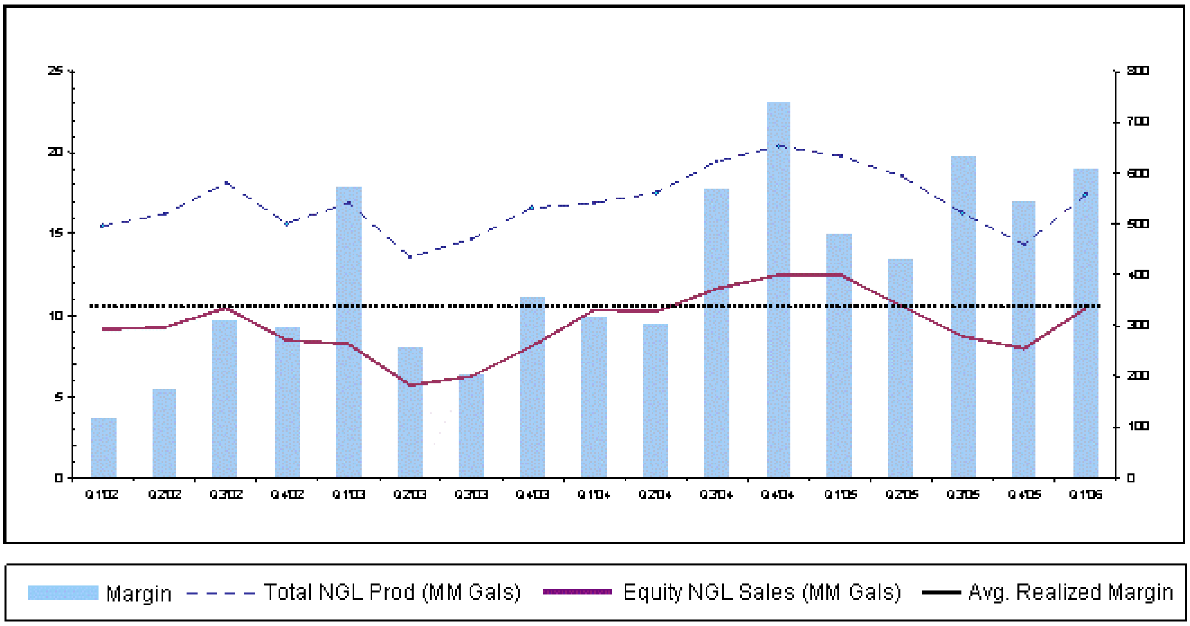
Major Growth Projects included in Guidance ($ Millions):

Project Name – In Service Date	2006	2007	2008
Opal TXP IV (1Q 2006)	$30	-	-
Opal TXP V (2Q 2007)	50	$15	-
Blind Faith (3Q 2007)	90	85	-
Wamsutter Phase II (4Q 2007)	10	65	-

Note: If guidance has changed, previous guidance from 02/28/2006 is shown in italics directly below.

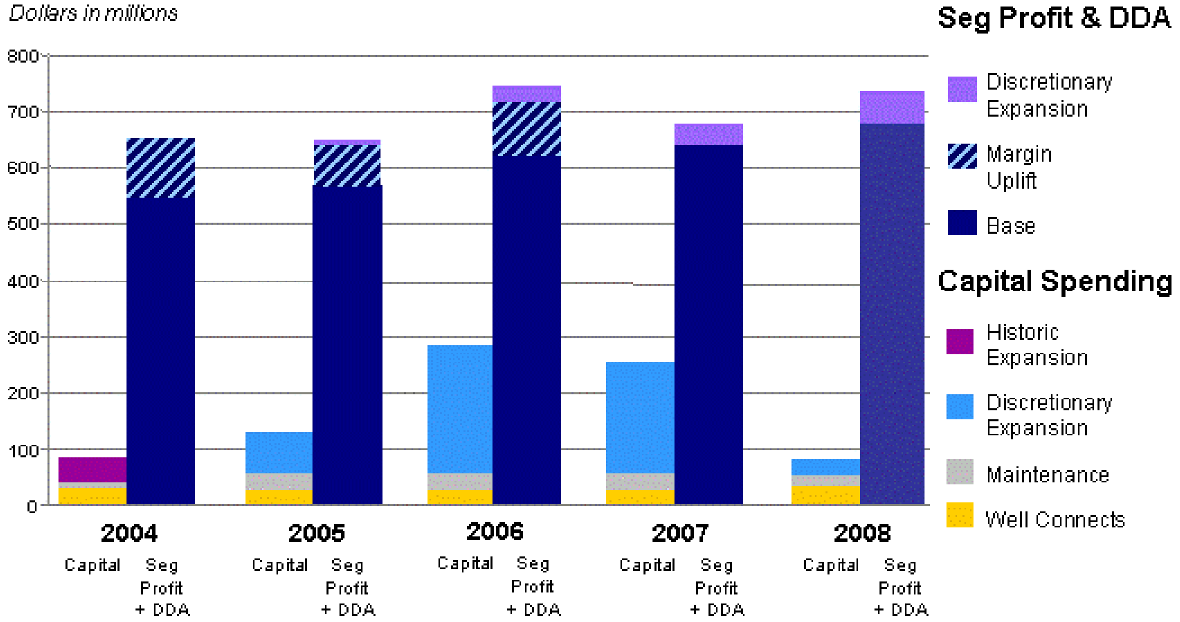
Margins Above Average

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 2001-2005. Does not include Discovery volumes.

Strong Free Cash Flow

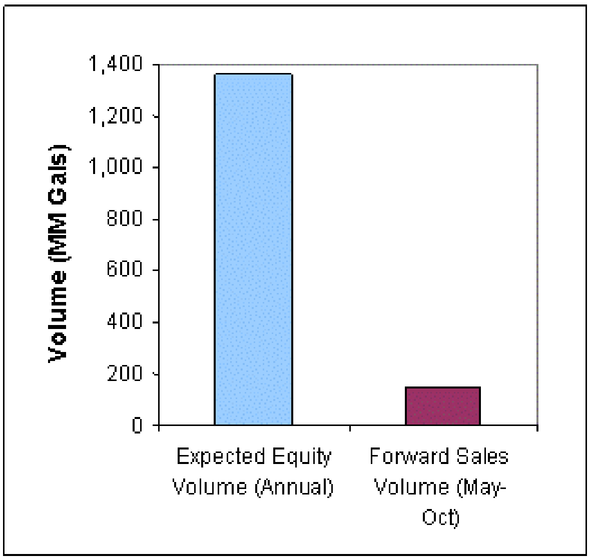


Note:
- *Segment Profit is stated on a recurring basis. Segment Profit for 2004 has been restated to reflect reclassifications*
- *Segment Profit + DDA and Capital Spending reflect midpoint of ranges.*
- *Margin uplift represents actual realized margin in excess of forecasted margin.*

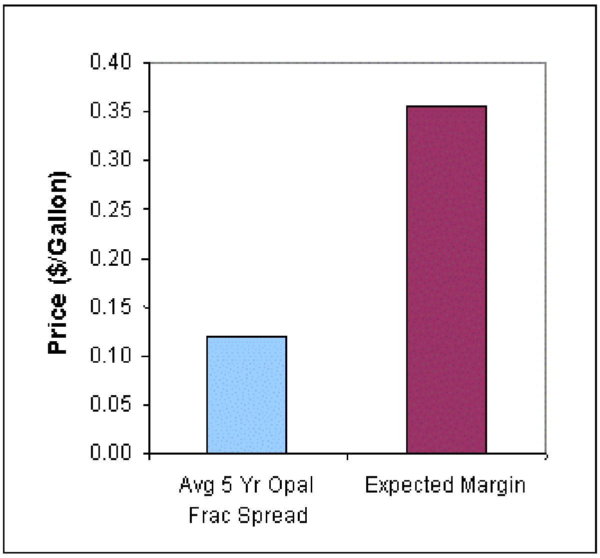
NGL Forward Sales

(as of April 28, 2006)

Amount of Forward Sales



Expected Margin @ NYMEX Strip



Expected equity volume does not include Discovery or Canada NGL volumes. Expected Margin calculated using executed NGL sales and Natural Gas Prices based upon average May – Oct NYMEX strip of $7.10/MMBtu and average May – Oct NWPL basis of $1.65/MMBtu.

Segment Profit

Dollars in millions	1st Quarter 2006	1st Quarter 2005
Segment Profit	$135	$167
Nonrecurring		
Excess royalty reserve reversal	(2)	-
Income related to prior period	-	(13)
Recurring segment profit	$133	$154

- **1Q05 to 1Q06 financial highlights include:**
  - 2006
    - $2 million - environmental credit sales
    - $15 million - higher O&M and G&A expenses
  - 2005 recurring income includes:
    - $5 million - Gulfstream completion fee
    - $3 million - operating tax adjustment

2006 Accomplishments

Northwest:

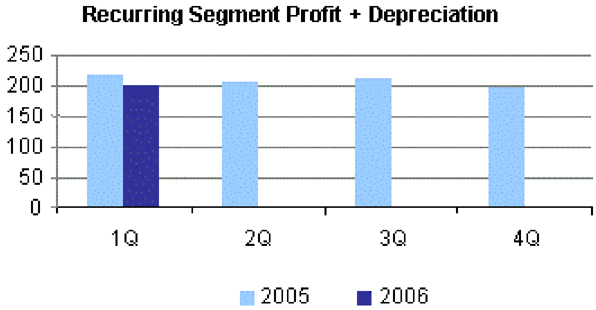
- FERC certificate application filed for Parachute Lateral
- Successful open season for Jackson Prairie incremental storage service
- Northwest partners with PG&E and Fort Chicago Energy Partners, LP to develop the Pacific Connector Gas Pipeline

Transco:

- Non-binding open seasons completed for Mobile Bay South and Production Area Mainline expansions

Gulfstream:

- 23-year transportation agreement reached with FPL to provide up to 345 MDth/d
  - Fully subscribes mainline capacity on a long-term basis
- Open season completed for compression-based expansion adding up to 200 MDth/d



2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$475 - 520	$585 - 655	$590 - 665
Annual DD&A	280 - 300	290 - 310	295 - 315
Segment Profit + DD&A	$755 - 820	$875 - 965	$885 - 980
Capital Spending	$710 - 785	$390 - 490	$410 - 510

Note: If guidance has changed, previous guidance from 02/28/06 is shown in italics directly below.

2006-08 Capital Spending Detail

Dollars in millions	2006	2007	2008
Normal Maintenance/Compliance	$340 - 405	$210 - 265	$180 - 260
Northwest 26-inch Replacement	276	2	-
Expansion	95 - 105	180 - 220	230 - 250
Total	$710 - 785	$390 - 490	$410 - 510

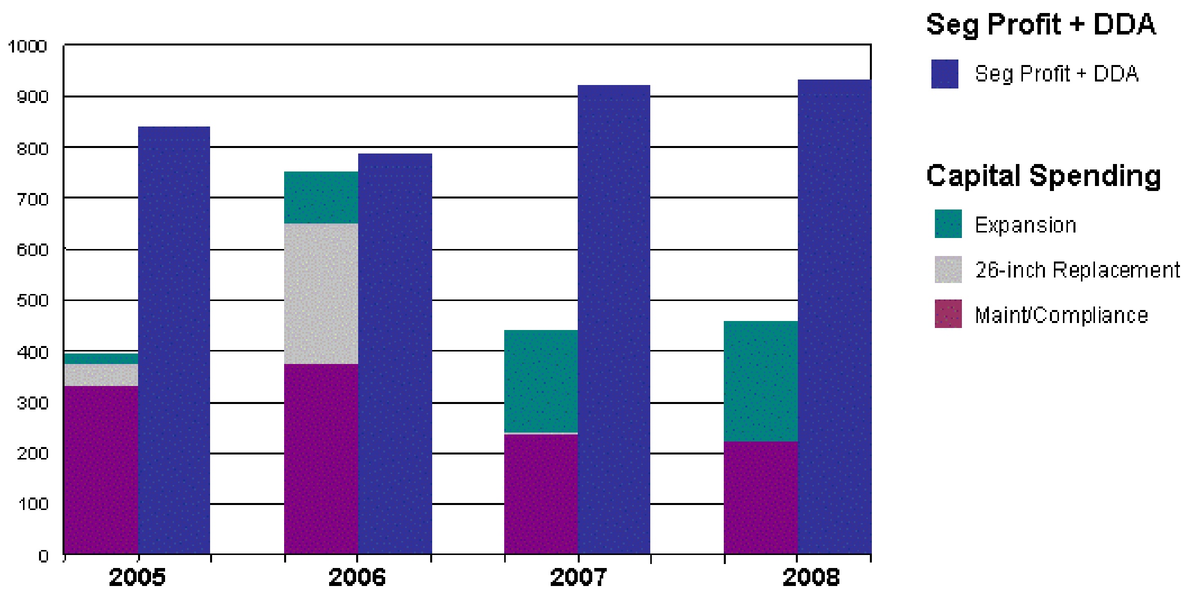
[1]**Major Growth Projects (in guidance):**	2006	2007	2008	1st full yr Seg. Profit
Parachute (In Service 1/07)	$50 - 60			$8
Leidy to Long Island (In Service11/07)	10 - 15	$85 - 100	$1 - 5	20
Potomac (In Service 11/07)	5 - 10	55 - 65	1 - 5	11
Sentinel (In Service 11/08)	10 - 15	35 - 45	195 - 205	41
Greasewood (In Service 11/08)			25 - 30	2 - 4

Note: If guidance has changed, previous guidance from 02/28/06 is shown in italics directly below.

Note: - Sum of ranges may not necessarily match total range

Strong Free Cash Flow

Dollars in millions



Note:
- Segment Profit is stated on a recurring basis.
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges for 2006 - 2008.

Segment Profit

Dollars in Millions	1st Qtr 2006	1st Qtr 2005
Segment Profit/(Loss)	**($23)**	**$114**
Nonrecurring:		
Accrual for Regulatory & Litigation Contingencies/Settlements	-	4
Expense Related to Prior Periods	-	7
Recurring Segment Profit/(Loss)	(23)	125
MTM Adjustment (Recurring)	**34**	**(108)**
Recurring Segment Profit/(Loss) After MTM Adjustment	**$11**	**$17**

- Variance in 1Q05 to 1Q06 Segment Profit after MTM primarily due to:
  - Increased power results offset by NG storage and legacy results
  - Decrease in expenses (including SG&A) of $27 million, includes $24 million gain related to sale of certain Enron receivables

2006-08 Guidance

Dollars in millions	2006	2007	2008
Prior Guidance - Segment Loss before MTM Adj	($235) - (135)	($160) - (10)	($150) - (0)
Est. Fwd Impact of 1Q06 MTM Earnings	30	(5)	(15)
New Guidance - Segment Loss before MTM Adj	($205) - (105)	($165) - (15)	($165) - (15)
	(235) - (135)	*(160) - (10)*	*(150) - (0)*
Estimated MTM Adjustments	255	215	215
	280	*210*	*200*
Segment Profit after MTM Adj	50 - 150	50 - 200	50 - 200
Recurring Segment Profit after MTM Adj	**$50 - 150**	**$50 - 200**	**$50 - 200**
Power Standalone Cash Flows [1]	**$50 - 150**	**$50 - 200**	**$50 - 200**

[1] 2006-2008 Portfolio cash flow guidance assumes no use of Working Capital. Changes in Working Capital are likely if future commodity prices are volatile or if collateral is returned to counterparties, or if counterparties exchange Letters of Credit for cash held by WMB. Payment of regulatory and litigation/settlement accruals are not included in portfolio cash flow guidance.

Note: If guidance has changed, previous guidance from 2/28/06 is shown in italics directly below.

1Q 2006 - Segment Profit/(Loss) to Cash Flow from Ops

Dollars in Millions	Commodity Power & NG	Working Capital/ Other	CFFO
Segment Profit/(Loss)	($26)	$3	($23)
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(43)		(43)
Add Realized Gains from MTM Previously Recognized	77		77
Segment Profit/(Loss) After MTM Adjustments	8	3	11
Total Working Capital Change[1&2]		(153)	(153)
Power Segment CFFO	8	(150)	(142)
Est. Working Capital Used for Other Business Units		151	151
Power Standalone CFFO	**$8**	**$1**	**$9**

[1]Significant amount of Working Capital used was returned to two counterparties due to commodity settlements and commodity price changes.

[2]Collateral returned does not impact total WMB liquidity because collateral received is excluded from calculation of available WMB liquidity.

Cash Flow Analysis

Estimated undiscounted dollars in millions

Actual vs. Forecast 2006	1Q06A	1Q06F	YTD Variance	2006A+F	2007F	2008F
Tolling Demand Payment Obligations	($86)	($86)	$0	($397)	($402)	($407)
Hedged Cash Flows [2]	131 [1]	136	(5)	585	503	524
Merchant Cash Flows [3]				43	92	85
SG&A and Other [4]	1	(21)	22	(85)	(85)	(80)
Total Cash Flows	$46	$29	$17	$146	$108	$122
Working Capital & Other [5]	(188)	0	(188)	(188)	0	0
Estimated Power Segment Cash Flows	($142)	$29	($171)	($42)	$108	$122

1 Q106 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities. Q106 forecast combines Hedged Cash Flow and Merchant Cash Flow estimates to present comparable to actual.

2 Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

3 Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

4 SG&A includes $24 million gain related to sale of certain Enron receivables

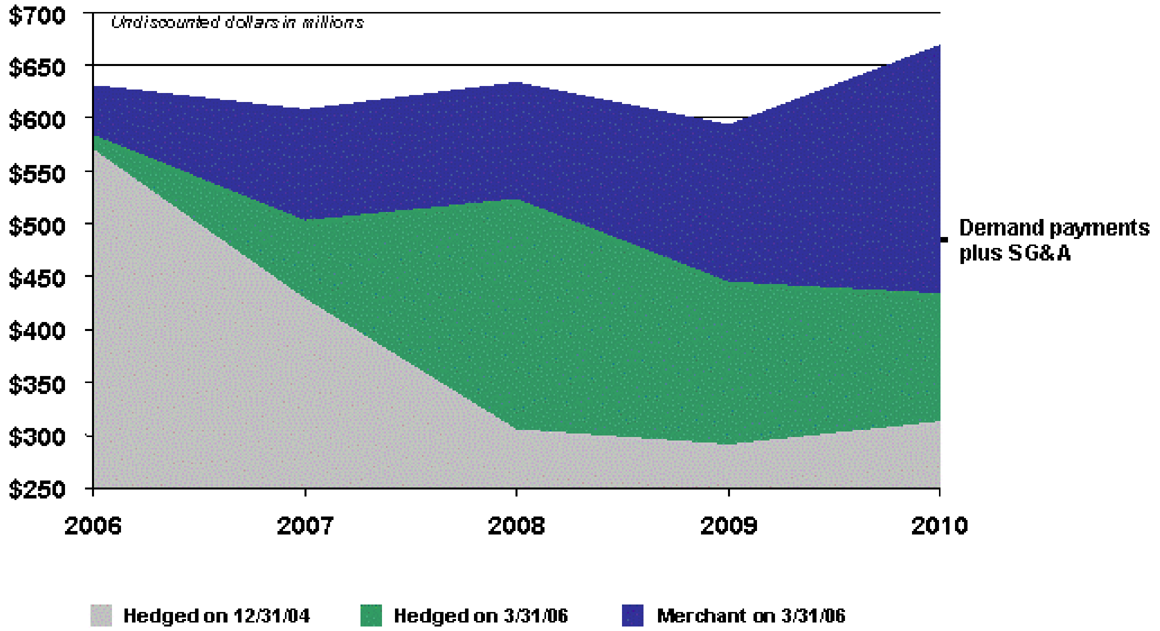
5 Working Capital & Other changes are zero in future periods, as they are not reasonably estimable.

Note: Q106 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 3/31/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

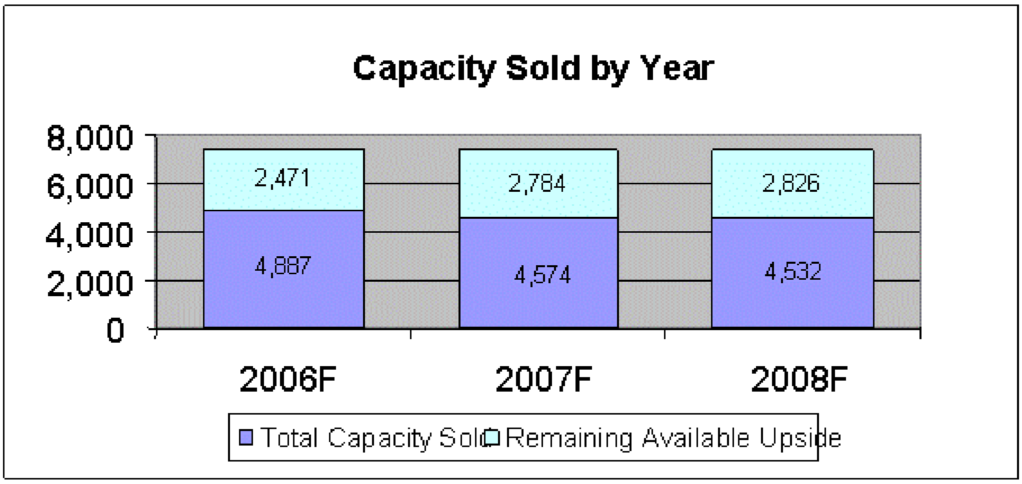
New contracts since February 28 call

Tenaska - Lindsay Hill	Southeast	Utility	56	Mar 06 - Dec 06
Tenaska - Lindsay Hill		Utility	106	Mar 07 - Dec 09
Red Oak (closed in April 06)	Northeast	Utility	100	Summer 07
Ironwood (closed in April 06)	Northeast	Muni	200	Jun 06 - May 07
Ironwood (closed in April 06)	Northeast	Muni	200	Jun 06 - May 07
Kinder Morgan (closed in April 06)	Mid Con	Utility	250	Summer 06
AES 400 (closed in Feb 06	West	Retail Aggregator	175	Jun06 - Dec 06

New Deals Since 2004 Add to Estimated Hedged Cash Flows



Capacity Sold by Year



1Q06 Financial Statement Changes for Derivatives

- During 1Q06, Williams reported the following changes related to its derivative portfolio:

	Balance Sheet		Income Statement	
	Der A/L	OCI	MTM Gain/(Loss)	Realized (Gain)/Loss
Total Change in Consolidated Derivative Values	$269	$189	$51	$29
Less change in Option Premiums/Prudency/Other	3			3
Remaining Change in Consolidated Derivative Values	$266	$189	$51	$26
Change in E&P Hedge Values	477	375	8	
- Prior MTM Realized (Ineffectiveness)				(2)
- OCI Realized				96
Change in Power Hedge Values	(211)	(186)	43	
- Prior MTM Realized				(77)
- OCI Realized				9

- The net change in Derivative Assets and Liabilities for E&P was positive reflecting the 2006 decrease in gas prices against a short derivative position
- The net change in Derivative Assets and Liabilities for Power was negative, reflecting the 2006 decrease in gas prices against a long derivative position

NOTE: Change in OCI shown is before taxes. Therefore, change shown does not tie to balance sheet change which is net of taxes.

West Undiscounted Cash Flows

Dollars in millions

West Power Portfolio Estimated as of 3/31/06	Q1'06A	2006F+A	2007F	2008F
Tolling Demand Payment Obligations	($38)	($152)	($153)	($155)
Hedged Cash Flows [2]	$89	$430	$400	$377
Merchant Cash Flows [3]	$0	$1	$1	$4
Total Cash Flows	$51	$279	$248	$226
Capacity Available (in MW)		3,783	3,783	3,783
Total Capacity Sold		2,765	3,392	3,348
Remaining Capacity Available		1,018	391	435

[1] Q106 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: Q106 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 3/31/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Mid-Con Undiscounted Cash Flows

Dollars in millions

Mid-Continent Power Portfolio Estimated as of 3/31/06	Q1'06A	2006F+A	2007F	2008F
Tolling Demand Payment Obligations	($13)	($88)	($89)	($90)
Hedged Cash Flows[2]	$4	$29	$31	$29
Merchant Cash Flows[3]	$0	$15	$19	$21
Total Cash Flows	($9)	($44)	($39)	($40)
Capacity Available (in MW)		1,296	1,296	1,296
Total Capacity Sold		639	600	600
Remaining Capacity Available		657	696	696

[1] Q106 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: Q106 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 3/31/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

East Undiscounted Cash Flows

Dollars in millions

East Power Portfolio Estimated as of 3/31/06	**Q1'06A**	**2006F+A**	**2007F**	**2008F**
Tolling Demand Payment Obligations	($35)	($158)	($160)	($162)
Hedged Cash Flows [2]	$34	$127	$71	$118
Merchant Cash Flows [3]	$0	$28	$71	$59
Total Cash Flows	($1)	($3)	($18)	$15
Capacity Available (in MW)		2,279	2,279	2,279
Total Capacity Sold		1,483	582	584
Remaining Capacity Available		796	1,697	1,695

[1] Q106 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities.

[2] Forecasted Hedged Cash Flows represents (1) the estimated cash flows from hedges such as resale of tolls, heat rate options, full requirements contracts and fixed price power and gas contracts and (2) the estimated value of the tolling (spread option) cash flows associated with those hedges.

[3] Forecasted Merchant Cash Flows represents the tolling (spread option) cash flows which have not been hedged.

Note: Q106 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 3/31/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

WMB Collateral Outstanding

	As of 3/31/06				
Dollars in millions	**E&P**	**Midstream**	**Power**	**Corp./ Other**	**Total**
Margins & Ad. Assur.	$152	$0	$27	$0	$179
Prepayments	0	1	9	0	10
Subtotal	152	1	36	0	189
Letters of Credit	497	138	427	64	1126
Total as of 3/31/06	649	139	463	64	1315
Total as of 12/31/05	746	243	343	91	1423
Change	($97)	($104)	$120	($27)	($108)

WMB Collateral Sensitivity

Dollars in millions

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

Days	3/31/2006	12/30/2005	9/30/2005	6/30/2005
30	($223)	($325)	($469)	($178)
180	($769)	($559)	($868)	($458)
360	($626)	($567)	($926)	($351)

Assumption: The Margin numbers above consist of only forward marginable positions.

Sensitivity Analysis

Dollars in millions, except per unit increases

	Enterprise [1] Natural Gas Per MMBtu	Power Co. [2] Power Per MWh	Midstream [3] Processing Margin Per Gallon of NGL's
Increase	**$0.10**	**$1**	**$0.01**
2006 [4]	$2-$5	$2-$4	$7-$11
2007	$8-$10	$6-$8	$10-$15
2008	$20-$22	$9-$11	$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 Power prices across the entire Power Co. portfolio
[3] Assumes a non-correlated change in NGL processing spread (i.e. change in NGL price only).
[4] 2006 metrics reflect a nine month impact, 2007-2008 metrics reflect a full twelve month imact.

Debt Balance[1]

Dollars in millions

		Avg. Cost
Debt Balance @ 12/31/05	**$7,713**	**7.6%**
Early Conversions	(220)	
Scheduled Debt Retirements & Amortization	(64)	
Debt Balance @ 3/31/06	**$7,429**	**7.7%**
Fixed Rate Debt @ 03/31/06	**$6,788**	**7.8%**
Variable Rate Debt @ 03/31/06	**$641**	**6.7%**

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

EPS Metrics

2006	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	-	-	-	-
Recurring EPS	0.23	-	-	-	-
Recurring EPS after MTM Adj.	**0.26**	-	-	-	-
Average Shares (MM)	607	-	-	-	-

2005	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.34	$0.07	$0.01	$0.11	$0.53
Recurring EPS	0.33	0.11	(0.01)	0.28	0.72
Recurring EPS after MTM Adj.	**0.22**	**0.17**	**0.22**	**0.26**	**0.86**
Average Shares (MM)	599	579	581	609	606

Consolidated

2006 Interest Expense Forecast Guidance

Dollars in millions	**2006**
Interest on Long-Term Debt	\$574 - \$591
Amortization Discount/Premium and other Debt Expense	35 - 43
Credit Facilities: (incl. Commitment Fees plus LC Usage)	42 - 52
Interest on other Liabilities	22 - 32
Interest Expense	\$673 - \$718
Less: Capitalized Interest	(8) - (13)
Net Interest Expense Guidance	**\$665 - \$705**

2006 Effective Tax Rates

	2006	
	First Quarter	
Statutory Rate	77	35%
State	12	6%
Foreign	0	0%
Other	(1)	-1%
Tax Provision/(Benefit)	88	40%

	2006	2007	2008
Effective Tax Rate Guidance [1]	**39%**	**39%**	**39%**
Cash Tax Rate Guidance [2]	**8-13%**	**5-10%**	**9-14%**

Note 1: Additional income tax expense of $5-15 million in 2006, $10-15 in 2007 and $5-10 million in 2008 is also forecast.

Note 2: Discontinued operations in 2006 have an immaterial impact.

The Williams Companies, Inc.