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): August 3, 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))

Item 2.02. Results of Operations and Financial Condition.

On August 3, 2006, The Williams Companies, Inc. (“Williams” or the “Company”) issued a press release announcing its financial results for the quarter ended June 30, 2006. A copy of the press release and its accompanying highlights and reconciliation schedules are furnished as a part of this current report on Form 8-K as Exhibit 99.1 and is incorporated herein in its entirety by reference.

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

Item 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 August 3, 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 August 3, 2006, and its accompanying highlights and reconciliation schedules, publicly announcing its second quarter 2006 financial results.
Exhibit 99.2	Copy of Williams’ slide presentation to be utilized during the August 3, 2006, public conference call and webcast.

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

THE WILLIAMS COMPANIES, INC.

Date: August 3, 2006

/s/ Donald R. Chappel

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

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
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Exhibit 99.1

NewsRelease

NYSE:WMB

Date: Aug. 3, 2006

Williams Reports Second-Quarter 2006 Financial Results

- *99% Increase in Recurring Income After Mark-to-Market Adjustment*
- *Net Income Significantly Reduced by Legacy Litigation Settlement and Charges*
- *Company Raises Profit and Cap-Ex Guidance for 2006-2008: Key 2006 EPS Measure Rises 19%*
- *2Q Natural Gas Production Up 20% Compared With Last Year*
- *Williams Outlines Goal to Accelerate Drop-Downs to MLP*

Quarterly Summary Information	2Q 2006		2Q 2005	
Per share amounts are reported on a diluted basis	millions	per share	millions	per share
Income (loss) from continuing operations	$ (63.9)	$ (0.11)	$ 40.7	$ 0.07
Income (loss) from discontinued operations	$ (12.1)	$ (0.02)	$ 0.6	$ 0.00
Net income (loss)	$ (76.0)	$ (0.13)	$ 41.3	$ 0.07
Recurring income from continuing operations*	$ 112.6	$ 0.19	$ 65.9	$ 0.11
After-tax mark-to-market adjustments	$ 85.4	$ 0.14	$ 33.6	$ 0.06
Recurring income from continuing operations — after mark-to-market adjustment*	$ 198.0	$ 0.33	$ 99.5	$ 0.17

Year-to-Date Summary Information	YTD 2006		YTD 2005	
Per share amounts are reported on a diluted basis	millions	per share	millions	per share
Income from continuing operations	$ 67.2	$ 0.11	$ 242.9	$ 0.41
Income (loss) from discontinued operations	$ (11.3)	$ (0.02)	$ (0.5)	$ 0.0
Net income	$ 55.9	$ 0.09	$ 242.4	$ 0.41
Recurring income from continuing operations*	$ 248.5	$ 0.42	$ 264.3	$ 0.45
After-tax mark-to-market adjustments	$ 106.4	$ 0.17	$ (32.4)	$ (0.06)
Recurring income from continuing operations — after mark-to-market adjustment*	$ 354.9	$ 0.59	$ 231.9	$ 0.39

* 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 a second-quarter 2006 unaudited net loss of $76.0 million, or a loss of 13 cents per share on a diluted basis, compared with net income of $41.3 million, or 7 cents per share, for second-quarter 2005.

Results for second-quarter 2006 were significantly reduced by the after-tax impact of three legacy litigation charges totaling approximately $175 million. The combined impact of the charges on a pre-tax basis is $267.9 million.

These items include a $160.7 million pre-tax charge associated with an agreement in principle to settle securities litigation filed on behalf of purchasers of Williams' securities between 2000 and 2002; an $88.0 million pre-tax accrual, including $20 million in interest, associated with the Gulf Liquids jury verdicts this week; and a $19.2 million pre-tax loss from discontinued operations primarily related to an environmental indemnity arbitration ruling associated with a former business.

These nonrecurring charges and the effect of mark-to-market accounting obscure the company's strong performance overall. Margins for the company's natural gas liquids sales remain at historic highs and Williams continues to increase its natural gas production in the western United States.

Year-to-date through June 30, Williams reported net income of $55.9 million, or 9 cents per share on a diluted basis, compared with net income of $242.4 million, or 41 cents per share, for the first half of 2005.

On a basis to remove the effect of nonrecurring items and mark-to-market accounting, Williams earned 33 cents per share in second-quarter 2006, almost doubling the 17 cents per share from the same period a year ago.

For the first half of 2006, Williams earned 59 cents per share on a basis adjusted to remove the effect of nonrecurring items and mark-to-market accounting. That represents a 51 percent improvement compared with 39 cents per share on the same basis for the first half of 2005.

Higher results in 2006 are primarily attributable to increased natural gas liquids sales margins and increased natural gas production. Additional details about the nonrecurring items and mark-to-market adjustment for the second quarter and the first half of the year are included in this news release.

Recurring Results Adjusted to Remove the 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.

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 99 percent from a year ago to $198.0 million, or 33 cents per share, in second-quarter 2006 from $99.5 million, or 17 cents per share in second-quarter 2005.

For the first six months of 2006, recurring income from continuing operations — adjusted to remove the effect of mark-to-market accounting — was $354.9 million, or 59 cents per share, an increase of 53 percent compared with $231.9 million, or 39 cents per share, for the first half of 2005.

The improvement in 2006 is primarily the result of robust sales margins for natural gas liquids; increased natural gas production, particularly in the Piceance and Powder River basins; increased gathering and processing revenue in Midstream; and improved results in Power's gas and power portfolios.

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.

Williams Increases Guidance for 2006-2008

Williams has raised its guidance for 2006-2008 based on the company's strong first-half operations performance in 2006, anticipated increases in natural gas production volumes, and its outlook for crude oil prices — a key factor that has driven record-level sales margins for natural gas liquids.

The company now expects 95 cents to $1.20 for earnings per share in 2006 on a recurring basis adjusted to remove the effect of mark-to-market accounting, an increase of 19 percent compared with the previous expectation of 78 cents to $1.03.

Williams also is raising its expectations for consolidated segment profit for 2006 through 2008 on a recurring basis adjusted to remove the effect of mark-to-market accounting.

Updated Guidance — Recurring Segment Profit Adjusted for Mark-to-Market Effect

	NEW	PREVIOUS
2006	$1.69 billion-$2.01 billion	$1.52 billion-$1.86 billion
2007	$1.97 billion-$2.475 billion	$1.83 billion-$2.255 billion
2008	$2.2 billion-$2.875 billion	$2.015 billion-$2.58 billion

The company's overall expected capital budget has increased, as well. The increase in planned capital expenses is primarily for projects that support additional natural gas development, particularly in the Piceance Basin.

Updated Cap-Ex Guidance

	NEW	PREVIOUS
2006	$2.2 billion-$2.4 billion	$1.95 billion-$2.15 billion
2007	$1.775 billion-$1.975 billion	$1.6 billion-$1.8 billion
2008	$1.575 billion-$1.825 billion	$1.5 billion-$1.75 billion

CEO Perspective

"Williams' solid performance demonstrates that we're executing our business plan and taking action to deliver strong sustainable increases in shareholder value," said Steve Malcolm, chairman, president and chief executive officer.

"So far in 2006, we have invested $1 billion in our businesses, increased our dividend by 20 percent, completed a major transaction with our master limited partnership, eliminated virtually all of our secured debt, improved our credit ratings, and reached an agreement in principle to settle securities litigation.

"And although natural gas prices softened following a mild winter, these conditions have benefited our Midstream business tremendously. The combination of lower prices for natural gas and higher prices for crude oil has pushed the sales margins for natural gas liquids to new highs — highs that could become more of the norm based on the global factors that drive demand for crude oil.

"Now we're raising our guidance for earnings per share by 19 percent on a recurring basis adjusted for mark-to-market accounting. Equally important, we're looking at breakout growth in 2007 and beyond.

"We're drilling more natural gas wells than ever before, we're getting a boost from our previous deepwater investments, we're forecasting continued strength in NGL margins, and we're expecting new rates on our interstate pipeline systems to be effective early in 2007."

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.

Williams' businesses reported consolidated segment profit of $292.9 million in second-quarter 2006, an increase of 14 percent compared with $256.4 million a year ago.

Higher results in second-quarter 2006 are primarily attributable to robust margins for natural gas liquids sales and increased natural gas production, partially offset by higher operating costs and the $68 million portion of the Gulf Liquids litigation accrual recorded at Midstream. Results for the same period in 2005 were affected by a $49.1 million impairment charge to an equity investment in the Other segment.

On a basis adjusted to remove the effect of nonrecurring items and mark-to-market accounting, Williams had recurring consolidated segment profit of $499.3 million in second-quarter 2006, compared with $355.7 million a year ago — an increase of 40 percent.

2Q Consolidated Recurring Segment Profit Adjusted for Mark-to-Market Effect

	2Q '06 (millions)	2Q '05 (millions)
Segment profit	$ 292.9	$ 256.4
Nonrecurring adjustments	$ 68.0	$ 44.5
Recurring segment profit	$ 360.9	$ 300.9
Reverse forward unrealized mark-to-market (gains) losses	$ 38.6	$ (22.1)
Add realized mark-to-market gains that were previously recognized	$ 99.8	$ 76.9
Recurring segment profit after mark-to-market adjustments	$ 499.3	$ 355.7

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

	YTD '06 (millions)	YTD '05 (millions)
Segment profit	$ 705.2	$ 766.1
Nonrecurring adjustments	$ 59.7	$ 35.2
Recurring segment profit	$ 764.9	$ 801.3
Reverse forward unrealized mark-to-market gains	$ (4.4)	$ (243.2)
Add realized mark-to-market gains that were previously recognized	$ 176.9	$ 189.9
Recurring segment profit after mark-to-market adjustments	$ 937.4	$ 748.0

For the first half of 2006, Williams' businesses reported consolidated segment profit of $705.2 million, a decrease of 8 percent compared with $766.1 million for the first half of 2005. Results in the first half of 2005 benefited from $243.2 million of forward unrealized mark-to-market gains in Power, compared with only $4.4 million in the first half of 2006. The 2006 period also includes the $68 million Gulf Liquids litigation accrual.

On a basis adjusted to remove the effect of nonrecurring items and mark-to-market accounting, Williams had recurring consolidated segment profit of $937.4 million for the first half of 2006, compared with $748.0 million for the first half of 2005 — an increase of 25 percent.

The improvement in 2006 on an adjusted basis is primarily the result of significantly higher results in Midstream, Power and Exploration & Production.

Exploration & Production: Segment Profit and Volumes Up 20 Percent

Exploration & Production includes 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.

This business reported second-quarter 2006 segment profit of $119.8 million, comparable to segment profit of $118.3 million a year ago. The price for production sold was relatively flat from quarter-to-quarter, including the effect of legacy hedge positions. During the second quarter of 2006, Williams realized net domestic average prices of $4.18 per thousand cubic feet equivalent (Mcfe), compared with $4.16 a year ago.

The benefit of higher production volumes in the second quarter of 2006 was offset by increased lease operating expenses, including $9 million of prior-period expenses and higher work-over expenses; higher depreciation, depletion and amortization; and higher general and administrative expenses.

For the first six months of 2006, Exploration & Production reported segment profit of $267.4 million, an increase of 20 percent compared with $222.0 million for the first half of 2005.

The improvement in the first half of 2006 primarily reflects increased production volumes; higher net realized average prices for production sold in the first quarter; and an $11 million increase in unrealized gains from hedge ineffectiveness and forward mark-to-market gains on certain basis swaps not designated as hedges.

These increases were partially offset by the same factors previously noted for the second quarter, as well as the absence of an $8 million gain in 2005 on the sale of certain assets.

Average daily production from domestic and international interests was approximately 786 million cubic feet of gas equivalent (MMcfe) in second-quarter 2006, compared with 652 MMcfe in the first half of 2005 — an increase of 20 percent.

Second-quarter 2006 average daily production in the Piceance Basin was 413 MMcfe — up 34 percent compared with second-quarter 2005 production of 309 MMcfe. Production in the Powder River Basin increased, too — up 23 percent to 137 MMcfe, compared with 111 MMcfe a year ago.

Williams now has 23 rigs operating in the Piceance Basin of western Colorado — 10 more than it had at this time a year ago. The rig count includes six new-generation drilling rigs that are purpose-built for conditions in the tight-sands development. So far, Williams has seen an improvement in drilling efficiency of approximately 25 percent with the new rigs. Four more are scheduled for delivery this year.

Williams now plans to invest $1.15 billion to $1.25 billion in Exploration & Production in 2006 — an increase of $200 million from its previous plan. These investments primarily focus on increasing the pace of developing the company's natural gas reserves.

Williams also has increased its expectation for segment profit from Exploration & Production in 2006. The company now expects $550 million to $650 million in segment profit, an increase of $25 million from guidance provided in May this year. The increase is the result of anticipated increases in production volumes.

Midstream Gas & Liquids: 2Q Recurring Segment Profit Rises 82 Percent

Midstream provides gathering and processing services for oil and gas producers, along with natural gas liquids (NGL) services and olefins production.

This business reported segment profit of $130.7 million in the second quarter, up 20 percent compared with $109.1 million a year ago.

Excluding a nonrecurring charge of $68 million related to the Gulf Liquids litigation accrual, Midstream posted $198.7 million of recurring segment profit — an increase of 82 percent compared with a year ago.

The dramatic increase in Midstream's results is primarily because of historic highs for NGL sales margins. This is the eighth consecutive quarter that NGL sales margins have remained above the company's five-year average, reflecting sustained strength in high crude oil prices that support strong NGL prices. Williams markets natural gas liquids via equity volumes the company retains as payment-in-kind under certain processing contracts.

In addition, Williams experienced high growth in production handling volumes and revenues in the deepwater Gulf of Mexico, and higher fee-based gathering and processing revenues.

In second-quarter 2006, Midstream sold 361.3 million gallons of NGL equity volumes — about 7 percent higher than equity sales of 338.3 million gallons in second-quarter 2005.

For the first six months of 2006, Midstream reported segment profit of $282.2 million, an increase of 19 percent compared with $237.7 million for the first half of 2005.

The improvement in 2006 primarily reflects a $79 million increase in natural gas liquids sales margins; significantly higher production handling volumes and revenues in the deepwater Gulf of Mexico; and higher fee-based gathering and processing revenues. These increases were partially offset in the first half by the Gulf Liquids litigation accrual and higher costs from maintenance expenses.

Year-to-date through June 30, Midstream sold 695.0 million gallons of domestic NGL equity volumes, a decrease of 6 percent compared with equity sales of 737.0 million gallons in the first half of 2005. Lower volumes of equity sales in the first half of 2006 were primarily the result of an increase in volumes subject to fee-based processing contracts in the first quarter.

The Cameron Meadows natural gas plant in Louisiana's Cameron Parish has been processing approximately 250-270 million cubic feet per day (MMcf/d) since returning to partial service in February. The facility is scheduled to return to its full design capacity of 500 MMcf/d by the end of August. The plant was damaged by Hurricane Rita last September.

In May, Williams reached an agreement with a third-party to develop the Overland Pass pipeline. Williams initiated the 750-mile project last year to provide an additional outlet for natural gas liquids produced at the company's Wyoming processing plants. The third-party has reimbursed Williams' development costs and will construct the pipeline. Williams retained a 1 percent ownership interest and has the option to increase its ownership to 50 percent. Start-up is planned for early 2008.

During the second quarter, Williams also completed a transaction that involved the drop-down of a 25.1 percent interest in Williams Four Corners LLC gathering and processing assets to Williams Partners L.P. (NYSE:WPZ) for $360 million. The partnership financed the transaction with $150 million in private debt and an equity offering that produced approximately $225 million in net proceeds.

Williams today said its goal is to complete similar transactions during the next six months — ranging in value from $1 billion to $1.5 billion — involving its gathering and processing assets with Williams Partners L.P. Williams has a portfolio of qualifying assets that support annual drop-downs of $1 billion to $2 billion through 2008.

The terms, including price, of any transactions between the company and the partnership are subject to approval by the boards of directors of each Williams and the general partner of Williams Partners. The terms also will be subject to approval by the conflicts committee of the board of directors of the general partner of Williams Partners.

Williams is raising its guidance again for segment profit it expects from Midstream in 2006 based on its outlook for strong NGL prices. The company now expects $550 million to $675 million in segment profit for this business. The company's prior guidance in May was $500 million to $600 million in segment profit for Midstream.

Gas Pipeline: Northwest Files Rate Case, Transco to Follow

Gas Pipeline primarily delivers natural gas to markets along the Eastern Seaboard, in the Northwest, and in Florida. This business reported second-quarter 2006 segment profit of $122.7 million, down 25 percent compared with $164.5 million a year ago.

The second quarter of 2005 benefited from $21.7 million in prior-period adjustments, including a $17.1 million reduction to pension expense. Results in the second-quarter of 2006 benefited from $2.8 million in higher equity earnings, which were more than offset by higher operating and maintenance costs and higher selling, general and administrative costs.

For the first six months of 2006, Gas Pipeline reported segment profit of $257.4 million, down 22 percent compared with $331.9 million for the first half of 2005.

The reduction in results for the first half of 2006 is attributable to higher operating and maintenance costs and higher selling, general and administrative costs, including the absence of $34.8 million in prior-period adjustments recorded in the first half of 2005.

Transco and Northwest Pipeline are proceeding with new rate case filings at the Federal Energy Regulatory Commission to reflect, among other things, current levels of operating costs and rate base. Northwest Pipeline filed its rate case on June 30 and Transco expects to file its rate case by Aug. 31. The new rates for both pipelines are expected to be effective, subject to refund, in first-quarter 2007.

Separately, FERC has approved Transco's application for an expansion project to add 100,000 dekatherms of firm capacity between Leidy, Pa., and Long Island, N.Y. Construction on the $121 million project is slated to begin in January 2007, with a projected in-service date of November 2007.

Williams also owns a 50-percent interest in the Gulfstream Natural Gas System, L.L.C., joint venture. In May, Gulfstream reached a new customer agreement that will require the first expansion to the original mainline capacity of nearly 1.1 billion cubic feet. Gulfstream expects to begin construction of the 17-mile, 155,000-dekatherm Phase IV expansion in January 2008.

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

Power: Solid Performance as Expected

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

2Q Power Recurring Segment Profit (Loss) Adjusted for Mark-to-Market Effect

	2Q '06 (millions)	2Q '05 (millions)
Segment loss	$ (79.6)	$ (75.0)
Nonrecurring adjustments	$ 0.0	$ 13.1
Recurring segment loss	$ (79.6)	$ (61.9)
Mark-to-market adjustments — net	$ 138.4	$ 54.8
Recurring segment profit (loss) after mark-to-market adjustments	$ 58.8	$ (7.1)

Power reported a second-quarter 2006 segment loss of $79.6 million, comparable to a segment loss of $75.0 million for second-quarter 2005. Results include the effect of forward noncash unrealized mark-to-market gains and losses.

The slight decrease is primarily the result of lower noncash unrealized mark-to-market gains, partially offset by the absence of a $13.1 million litigation accrual in 2005 and higher accrual earnings in 2006.

On a basis adjusted for the effect of mark-to-market accounting, Power reported recurring segment profit of $58.8 million in second-quarter 2006, compared with a recurring segment loss of $7.1 million in 2005.

The improvement in second-quarter 2006 recurring segment profit adjusted to remove the effect of mark-to-accounting reflects improved results from the power and gas portfolios and lower miscellaneous expenses. The gas portfolio results include a benefit from monetizing certain forward basis positions, partially offset by realized losses on the natural gas storage portfolio that are expected to be recovered in 2007 when the inventory is sold.

YTD Power Recurring Segment Profit (Loss) Adjusted for Mark-to-Market Effect

	YTD '06 (millions)	YTD '05 (millions)
Segment profit (loss)	$ (102.1)	$ 39.1
Nonrecurring adjustments	$ 0.0	$ 24.5
Recurring segment profit (loss)	$ (102.1)	$ 63.6
Mark-to-market adjustments — net	$ 172.5	$ (53.3)
Recurring segment profit after mark-to-market adjustments	$ 70.4	$ 10.3

For the first six months of 2006, Power reported a segment loss of $102.1 million compared with segment profit of $39.1 million for the first half of 2005. That change is primarily the result of lower forward unrealized mark-to-market earnings this year, partially offset by higher realized accrual portfolio results.

The 2006 period includes forward unrealized mark-to-market gains of $4.4 million, compared with forward unrealized mark-to-market gains of $243.2 million in the first half of 2005. In first-quarter 2005, there were a significant number of contracts that had not yet been designated as FAS133 hedges, which incurred significant mark-to-market gains. The year-over-year variance resulted from fewer nondesignated contracts subject to mark-to-market accounting in 2006.

For the first six months of 2006, Power reported a recurring segment profit on a basis to remove the effect of mark-to-market accounting of $70.4 million, compared with $10.3 million for the first half of 2005. The increase in the first half of 2006 is primarily because of the improved power and gas portfolio results previously mentioned, as well as lower expenses from the positive effect of a $23.7 million gain on the sale of certain third-party receivables in the first quarter.

For 2006, Williams now expects a $150 million to $200 million segment loss from Power, which includes year-to-date unrealized mark-to-market earnings on derivative contracts but assumes no future change in fair value on these contracts. Williams previously expected a $105 million to $205 million loss in Power.

Williams expects Power to generate 2006 recurring segment profit of $75 million to $125 million after removing the effect of mark-to-market accounting. The company’s prior guidance from May for this measure was $50 million to $150 million.

Cash and Debt

At the close of business on June 30, 2006, Williams maintained total liquidity consisting of approximately $1.7 billion in unused and available revolving credit facilities; $980 million in unrestricted cash and cash equivalents; and approximately $400 million in other liquid investments. The unrestricted cash and cash equivalents includes $478 million in subsidiary cash, international cash and customer margin deposits.

During the second quarter, Williams retired $489 million of secured debt. The company has now retired or replaced all of its secured debt, with the exception of non-recourse project debt at its Venezuelan operations.

At June 30, Williams’ total outstanding debt was approximately $7.5 billion. Overall, the company has reduced its debt during the first half of 2006 by approximately $250 million on a net basis.

As Williams continues to support its planned capital investments during 2006, the company expects to conclude the year at a debt level that is comparable to or slightly greater than year-end 2005.

For the first half of 2006, net cash provided by operating activities was $673.3 million, compared with $793.3 million for the first half of 2005. Net cash this year is primarily being reinvested in capital expenditures. Williams made approximately $1 billion in capital expenditures in the first half this year.

Today's Analyst Call

Williams' management will discuss the company's second-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) 810-0924. International callers should dial (913) 981-4900. Callers should dial in at least 10 minutes prior to the start of the discussion.

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

Form 10-Q

The company is filing its Form 10-Q this week 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 annual report on Form 10-K filed with the Securities and Exchange Commission on March 9, 2006, and our quarterly reports on Form 10-Q available from our offices or from our website at www.williams.com.

Financial Highlights and Operating Statistics

(UNAUDITED)

Final

June 30, 2006

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

(UNAUDITED)

	2005					2006		
(Dollars in millions, except per-share amounts)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*Year*
Income (loss) from continuing operations available to common stockholders	$ 202.2	$ 40.7	$ 5.7	$ 68.8	$ 317.4	$ 131.1	($63.9)	$ 67.2
Income (loss) from continuing operations — diluted earnings (loss) per common share	$ 0.34	$ 0.07	$ 0.01	$ 0.11	$ 0.53	$ 0.22	($0.11)	$ 0.11
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)	—	(2.0)
Total Gas Pipeline nonrecurring items	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	(2.0)
Midstream Gas & Liquids								
Accrual for Gulf Liquids litigation contingency	—	—	—	—	—	—	68.0	68.0
Settlement of an international contract dispute	—	—	—	—	—	(6.3)	—	(6.3)
Total Midstream Gas & Liquids nonrecurring items	—	—	—	—	—	(6.3)	68.0	61.7
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)	68.0	59.7
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	—	—	—
Securities litigation settlement and related costs (1)	—	—	—	9.4	9.4	1.2	160.7	161.9
Reversal of interest accrual related to reversal of litigation contingency noted above (Interest accrued — Gas Pipeline — TGPL)	—	—	—	—	—	(5.0)	—	(5.0)
Early debt retirement costs (Corporate and Exploration & Production)	—	—	—	—	—	27.0(1)	4.4	31.4
Gain on sale of Algar/Triangulo shares (Investing income / loss — Other)	—	—	—	—	—	(6.7)	—	(6.7)
Interest related to Gulf Liquids litigation contingency (Interest accrued — Midstream)	—	—	—	—	—	—	20.0	20.0
	2.7	(8.6)	18.8	9.4	22.3	16.5	185.1	201.6
Total nonrecurring items	(6.6)	35.9	(16.7)	167.5	180.1	8.2	253.1	261.3
Tax effect for above items (1)	(2.8)	10.7	(6.4)	48.0	49.5	3.4	76.6	80.0
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	$ 112.6	$ 248.5
Recurring diluted earnings (loss) per common share	$ 0.33	$ 0.11	($0.01)	$ 0.28	$ 0.72	$ 0.23	$ 0.19	$ 0.42
Weighted-average shares — diluted (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	598,634

[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%. The tax rate applied to nonrecurring items for 2nd quarter 2006 has been adjusted for the effect of nondeductible expenses associated with securities litigation settlement and related costs and early debt retirement costs related to our convertible debt.

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.

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	2006 2nd Qtr	2006 Year
Revenues	$ 2,954.0	$ 2,871.2	$ 3,082.3	$ 3,676.1	$ 12,583.6	$ 3,027.5	$ 2,715.1	$ 5,742.6
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	2,273.8	4,862.5
Selling, general and administrative expenses	73.5	62.7	90.6	98.6	325.4	71.0	109.3	180.3
Other (income) expense — net	(1.8)	21.9	(21.4)	62.5	61.2	(22.3)	61.7	39.4
Total segment costs and expenses	2,462.0	2,576.2	2,895.4	3,324.0	11,257.6	2,637.4	2,444.8	5,082.2
Equity earnings	17.7	9.8	17.6	20.5	65.6	22.2	23.1	45.3
Loss from investments	—	(48.4)	—	(60.7)	(109.1)	—	(0.5)	(0.5)
Total segment profit	**509.7**	**256.4**	**204.5**	**311.9**	**1,282.5**	**412.3**	**292.9**	**705.2**
Reclass equity earnings	(17.7)	(9.8)	(17.6)	(20.5)	(65.6)	(22.2)	(23.1)	(45.3)
Reclass loss from investments	—	48.4	—	60.7	109.1	—	0.5	0.5
General corporate expenses	(28.0)	(35.5)	(42.8)	(48.6)	(154.9)	(30.6)	(33.7)	(64.3)
Securities litigation settlement and related fees	—	—	—	—	—	(1.2)	(160.7)	(161.9)
Operating income	464.0	259.5	144.1	303.5	1,171.1	358.3	75.9	434.2
Interest accrued	(164.7)	(164.6)	(166.0)	(176.4)	(671.7)	(162.8)	(181.5)	(344.3)
Interest capitalized	1.1	1.4	1.8	2.9	7.2	3.0	4.0	7.0
Investing income (loss)	31.0	(17.2)	31.1	(21.2)	23.7	46.9	43.3	90.2
Early debt retirement costs	—	—	—	(0.4)	(0.4)	(27.0)	(4.4)	(31.4)
Minority interest in income of consolidated subsidiaries	(5.2)	(4.8)	(6.8)	(8.9)	(25.7)	(7.1)	(8.3)	(15.4)
Other income (expense) — net	5.5	8.1	(1.1)	14.6	27.1	8.1	8.0	16.1
Income (loss) 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	(63.0)	156.4
Provision (benefit) for income taxes	129.5	41.7	(2.6)	45.3	213.9	88.3	0.9	89.2
Income (loss) from continuing operations	**202.2**	**40.7**	**5.7**	**68.8**	**317.4**	**131.1**	**(63.9)**	**67.2**
Income (loss) from discontinued operations	(1.1)	0.6	(1.3)	(0.3)	(2.1)	0.8	(12.1)	(11.3)
Income before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5	315.3	131.9	(76.0)	55.9
Cumulative effect of change in accounting principle	—	—	—	(1.7)	(1.7)	—	—	—
Net income (loss)	**$ 201.1**	**$ 41.3**	**$ 4.4**	**$ 66.8**	**$ 313.6**	**$ 131.9**	**$ (76.0)**	**$ 55.9**
Diluted earnings per common share:								
Income (loss) from continuing operations	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.11)**	**$ 0.11**
Income (loss) from discontinued operations	—	—	—	—	—	—	**(0.02)**	**(0.02)**
Income before cumulative effect of change in accounting principle	**0.34**	**0.07**	**0.01**	**0.11**	**0.53**	**0.22**	**(0.13)**	**0.09**
Cumulative effect of change in accounting principle	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net income (loss)	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.13)**	**$ 0.09**
Weighted-average number of shares used in computation (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	598,634
Common shares outstanding at end of period (thousands)	570,501	571,502	572,922	573,592	573,592	595,007	595,562	595,562
Market price per common share (end of period)	$ 18.81	$ 19.00	$ 25.05	$ 23.17	$ 23.17	$ 21.39	$ 23.36	$ 23.36
Common dividends per share	$ 0.05	$ 0.05	$ 0.075	$ 0.075	$ 0.25	$ 0.075	$ 0.09	$ 0.165

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

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	2006 2nd Qtr	2006 Year
Segment profit (loss):								
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 267.4
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	257.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	282.2
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(102.1)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	0.3
Total segment profit	**$ 509.7**	**$ 256.4**	**$ 204.5**	**$ 311.9**	**$ 1,282.5**	**$ 412.3**	**$ 292.9**	**$ 705.2**
Nonrecurring adjustments:								
Exploration & Production	$ (7.6)	$ —	$ (21.7)	$ —	$ (29.3)	$ —	$ —	$ —
Gas Pipeline	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	(2.0)
Midstream Gas & Liquids	—	—	—	—	—	(6.3)	68.0	61.7
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)**	**$ 68.0**	**$ 59.7**
Recurring segment profit (loss):								
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	267.4
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	255.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	343.9
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(102.1)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	0.3
Total recurring segment profit	**$ 500.4**	**$ 300.9**	**$ 169.0**	**$ 470.0**	**$ 1,440.3**	**$ 404.0**	**$ 360.9**	**$ 764.9**

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

Exploration & Production
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	2006 *1st Qtr*	*2nd Qtr*	*Year*
Revenues:								
Production	$ 210.2	$ 234.8	$ 283.0	$ 344.4	$ 1,072.4	$ 286.8	$ 287.9	$ 574.7
Gas management	28.2	32.6	32.1	52.0	144.9	41.2	28.3	69.5
Net nonqualified hedge derivative income (loss)	(0.1)	0.6	(15.9)	9.8	(5.6)	12.8	(1.6)	11.2
International	10.8	11.6	16.3	14.7	53.4	16.0	15.1	31.1
Other	(0.1)	1.9	2.9	(0.7)	4.0	(0.8)	12.6	11.8
Total revenues	249.0	281.5	318.4	420.2	1,269.1	356.0	342.3	698.3
Segment costs and expenses:								
Depreciation, depletion and amortization (including International)	58.5	59.5	66.4	69.6	254.0	73.1	84.5	157.6
Lease and other operating expenses *	23.8	23.9	28.5	29.0	105.2	30.1	43.8	73.9
Operating taxes	21.1	23.9	26.7	29.4	101.1	31.8	28.1	59.9
Exploration expenses *	0.9	1.1	1.5	4.1	7.6	4.4	2.4	6.8
Gathering expense	5.6	6.0	5.0	8.1	24.7	6.4	7.5	13.9
Selling, general and administrative expenses (including International)	17.0	17.7	20.3	24.6	79.6	21.5	28.2	49.7
Gas management expenses	28.2	32.6	32.1	52.0	144.9	41.2	28.3	69.5
International (excluding DD&A and SG&A)	3.3	3.3	4.7	3.6	14.9	5.5	4.9	10.4
Other (income) expense — net	(9.6)	(1.2)	(19.8)	(0.7)	(31.3)	(0.6)	0.7	0.1
Total segment costs and expenses	148.8	166.8	165.4	219.7	700.7	213.4	228.4	441.8
Equity earnings — International	3.5	3.6	5.8	5.9	18.8	5.0	5.9	10.9
Reported segment profit	**103.7**	**118.3**	**158.8**	**206.4**	**587.2**	**147.6**	**119.8**	**267.4**
Nonrecurring adjustments	(7.6)	—	(21.7)	—	(29.3)	—	—	—
Recurring segment profit, pre-tax	**$ 96.1**	**$ 118.3**	**$ 137.1**	**$ 206.4**	**$ 557.9**	**$ 147.6**	**$ 119.8**	**$ 267.4**

* Amounts have been reclassified to the current classifications.

Operating statistics

	2005 1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	2006 1st Qtr	2nd Qtr	Year
Domestic:								
Total domestic net volumes (Bcfe)	51.1	55.0	57.9	59.5	223.5	59.5	67.1	126.6
Net domestic volumes per day (MMcfe/d)	568	604	629	646	612	661	738	700
Net domestic realized price ($/Mcfe) (1)	$ 4.001	$ 4.164	$ 4.801	$ 5.655	$ 4.688	$ 4.712	$ 4.177	$ 4.428
Production taxes per Mcfe	$ 0.413	$ 0.435	$ 0.462	$ 0.493	$ 0.452	$ 0.534	$ 0.420	$ 0.473
Lease and other operating expense per Mcfe	$ 0.466	$ 0.436	$ 0.492	$ 0.486	$ 0.471	$ 0.505	$ 0.653	$ 0.584

(1) Net realized price is calculated the following way: production revenues (including hedging activities and incremental margins related to gas management activities) divided by net volumes.

	2005 1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Year	2006 1st Qtr	2nd Qtr	Year
International:								
Total volumes including Equity Investee (Bcfe)	5.3	5.5	6.1	6.0	22.9	6.0	5.6	11.6
Volumes per day (MMcfe/d)	59	61	67	65	63	67	61	64
Volumes net to Williams (after minority interest) (Bcfe)	4.1	4.3	4.8	4.8	18.0	4.7	4.4	9.1
Volumes net to Williams per day (MMcfe/d)	46	48	53	51	49	53	48	50
Total Domestic and International:								
Volumes net to Williams (after minority interest) (Bcfe)	55.3	59.3	62.7	64.2	241.5	64.2	71.5	135.7
Volumes net to Williams per day (MMcfe/d)	614	652	682	697	662	714	786	750

Gas Pipeline
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 Year
Revenues:								
Northwest Pipeline	$ 80.3	$ 78.9	$ 79.6	$ 82.7	$ 321.5	$ 79.6	$ 80.0	$ 159.6
Transcontinental Gas Pipe Line	254.9	278.1	266.0	292.0	1,091.0	254.3	257.2	511.5
Other	0.1	—	0.2	—	0.3	0.1	0.1	0.2
Total revenues	335.3	357.0	345.8	374.7	1,412.8	334.0	337.3	671.3
Segment costs and expenses:								
Costs and operating expenses	160.4	193.3	177.6	250.7	782.0	177.2	192.8	370.0
Selling, general and administrative expenses	18.6	6.8	23.6	35.1	84.1	31.0	35.4	66.4
Other (income) expense — net	0.3	0.3	0.5	3.4	4.5	(1.4)	(3.4)	(4.8)
Total segment costs and expenses	179.3	200.4	201.7	289.2	870.6	206.8	224.8	431.6
Equity earnings	11.4	7.9	17.0	7.3	43.6	7.5	10.7	18.2
Income (loss) from investments	—	—	—	—	—	—	(0.5)	(0.5)
Reported segment profit:								
Northwest Pipeline	39.7	36.5	39.1	37.2	152.5	33.3	32.8	66.1
Transcontinental Gas Pipe Line	117.9	121.8	107.0	50.1	396.8	95.8	81.3	177.1
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	14.2
Total reported segment profit	**167.4**	**164.5**	**161.1**	**92.8**	**585.8**	**134.7**	**122.7**	**257.4**
Nonrecurring adjustments:								
Northwest Pipeline	—	—	—	—	—	—	—	—
Transcontinental Gas Pipe Line	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	(2.0)
Other	—	—	—	—	—	—	—	—
Total nonrecurring adjustments	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	—	(2.0)
Recurring segment profit:								
Northwest Pipeline	39.7	36.5	39.1	37.2	152.5	33.3	32.8	66.1
Transcontinental Gas Pipe Line	104.8	100.1	92.8	87.4	385.1	93.8	81.3	175.1
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	14.2
Total recurring segment profit, pre-tax	**$ 154.3**	**$ 142.8**	**$ 146.9**	**$ 130.1**	**$ 574.1**	**$ 132.7**	**$ 122.7**	**$ 255.4**
Operating statistics								
Northwest Pipeline								
Throughput (TBtu)	181.2	146.2	152.9	192.6	672.9	179.7	142.7	322.4
Average daily transportation volumes (TBtu)	2.0	1.6	1.7	2.1	1.9	2.0	1.6	1.8
Average daily firm reserved capacity (TBtu)	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Transcontinental Gas Pipe Line								
Throughput (TBtu)	537.7	427.9	453.6	466.6	1,885.8	502.8	427.0	929.8
Average daily transportation volumes (TBtu)	6.0	4.7	4.9	5.1	5.2	5.6	4.6	5.1
Average daily firm reserved capacity (TBtu)	6.9	6.5	6.4	6.8	6.7	7.0	6.4	6.7

Midstream Gas & Liquids
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *Year*
Revenues:								
Gathering	$ 70.6	$ 74.2	$ 74.0	$ 75.8	$ 294.6	$ 76.8	$ 79.0	$ 155.8
Processing	23.5	24.3	25.5	22.9	96.2	24.9	27.4	52.3
Venezuela fee revenue	36.5	37.8	40.4	38.8	153.5	38.9	38.0	76.9
NGL sales from gas processing	285.1	247.0	244.2	259.0	1,035.3	263.7	292.6	556.3
Production handling and transportation	18.6	20.4	14.7	20.6	74.3	37.2	33.2	70.4
Olefins sales (Incl Gulf and Canada)	146.6	114.2	121.4	185.3	567.5	148.9	131.4	280.3
Trading/marketing sales	588.0	574.4	522.0	578.1	2,262.5	709.0	806.1	1,515.1
Other revenues	23.7	33.2	31.7	39.1	127.7	34.4	30.7	65.1
	1,192.6	1,125.5	1,073.9	1,219.6	4,611.6	1,333.8	1,438.4	2,772.2
Intrasegment eliminations	(385.6)	(345.4)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(749.3)
Total revenues	807.0	780.1	754.7	890.9	3,232.7	979.4	1,043.5	2,022.9
Segment costs and expenses:								
NGL cost of goods sold	225.1	202.4	189.6	218.3	835.4	199.9	172.7	372.6
Olefins cost of goods sold	118.7	104.0	102.2	163.5	488.4	132.8	108.1	240.9
Trading/marketing cost of goods sold	584.0	574.7	510.1	575.8	2,244.6	716.7	799.1	1,515.8
Venezuela operating costs	16.1	16.0	17.4	17.6	67.1	16.8	18.1	34.9
Operating costs	101.6	101.5	112.8	113.9	429.8	120.6	120.7	241.3
Other								
Selling, general and administrative expenses	22.9	21.0	23.1	29.3	96.3	23.3	25.2	48.5
Other (income) expense — net	2.6	1.7	0.8	(1.7)	3.4	(17.9)	70.0	52.1
Intrasegment eliminations	(385.5)	(345.5)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(749.3)
Total segment costs and expenses	685.5	675.8	636.8	788.0	2,786.1	837.8	919.0	1,756.8
Equity earnings	7.1	4.1	3.2	9.2	23.6	9.9	6.2	16.1
Income from investments	—	0.7	—	0.3	1.0	—		—
Reported segment profit	**128.6**	**109.1**	**121.1**	**112.4**	**471.2**	**151.5**	**130.7**	**282.2**
Nonrecurring adjustments	—	—	—	—	—	(6.3)	68.0	61.7
Recurring segment profit, pre-tax	**$ 128.6**	**$ 109.1**	**$ 121.1**	**$ 112.4**	**$ 471.2**	**$ 145.2**	**$ 198.7**	**$ 343.9**
Operating statistics								
Gathering volumes (TBtu)	315.5	323.6	310.3	303.9	1,253.3	296.9	300.1	597.0
Gathering margins ($/MMBtu)	$ 0.2237	$ 0.2292	$ 0.2386	$ 0.2496	$ 0.2351	$ 0.2590	$ 0.2634	$ 0.2610
Processing volumes (TBtu)	181.0	184.5	190.3	165.6	721.4	191.8	204.8	396.6
Processing rate ($/MMBtu)	$ 0.1299	$ 0.1316	$ 0.1342	$ 0.1381	$ 0.1334	$ 0.1298	$ 0.1340	$ 0.1320
NGL equity sales (million gallons)	398.7	338.3	276.4	255.8	1,269.2	333.7	361.3	695.0
NGL margin ($/gallon)	$ 0.1503	$ 0.1318	$ 0.1976	$ 0.1565	$ 0.1569	$ 0.1900	$ 0.3319	$ 0.2644
Olefins sales (Ethylene & Propylene) (million lbs)	266.5	265.6	258.1	275.9	1,066.1	259.2	196.8	456.0

Power
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	2006 *1st Qtr*	*2nd Qtr*	*Year*
Revenues:								
Natural gas & power	$ 2,066.3	$ 1,998.6	$ 2,244.3	$ 2,787.0	$ 9,096.2	$ 2,053.3	$ 1,606.6	$ 3,659.9
Crude & refined products	(1.1)	(0.2)	(1.6)	0.1	(2.8)	—	—	—
Other	(0.3)	1.0	0.2	(0.4)	0.5	(0.1)	0.4	0.3
Total revenues	2,064.9	1,999.4	2,242.9	2,786.7	$ 9,093.9	2,053.2	1,607.0	$ 3,660.2
Segment costs and expenses:								
Costs and operating expenses	1,930.3	2,041.1	2,450.9	2,750.2	9,172.5	2,082.1	1,671.4	3,753.5
Selling, general and administrative expenses	16.0	16.9	21.1	10.5	64.5	(4.5)	18.9	14.4
Other (income) expense — net	5.6	17.3	(1.7)	95.5	116.7	(2.1)	(3.4)	(5.5)
Total segment costs and expenses	1,951.9	2,075.3	2,470.3	2,856.2	9,353.7	2,075.5	1,686.9	3,762.4
Equity Earnings	1.1	0.9	1.0	0.1	3.1	(0.2)	0.3	0.1
Reported segment profit (loss)	**114.1**	**(75.0)**	**(226.4)**	**(69.4)**	**(256.7)**	**(22.5)**	**(79.6)**	**(102.1)**
Nonrecurring adjustments	11.4	13.1	0.4	91.7	116.6	—	—	—
Recurring segment profit (loss), pre-tax	**$ 125.5**	**$ (61.9)**	**$ (226.0)**	**$ 22.3**	**$ (140.1)**	**$ (22.5)**	**$ (79.6)**	**$ (102.1)**
Operating statistics								
Volumes								
Natural gas (Bcfd)								
Sales to third parties	1.7	1.8	1.7	1.7	1.7	1.7	1.5	1.6
Sales to other segments	0.6	0.4	0.3	0.3	0.4	0.4	0.4	0.4
For use in tolling agreements and by owned generation	0.2	0.2	0.3	0.1	0.2	0.1	0.2	0.2
Total managed	2.5	2.4	2.3	2.1	2.3	2.2	2.1	2.2
Crude & refined products (MBPD)	—	—	—	—	—	—	—	—
Power (GWh)	14,832	15,906	21,690	14,559	66,987	11,505	12,949	24,454

Additional statistics

Value at risk

One day VaR - 95% confidence level	**Quarter ended 6/30/2006 (in Millions)**
Trading	$3.1MM
Non-Trading	$24.9MM
Aggregate Earnings VaR	$5.6MM

One day VaR - 95% confidence level	**Quarter ended 3/31/2006 (in Millions)**
Trading	$3.8MM
Non-Trading	$6.0MM
Aggregate Earnings VaR	$9.2MM

Net Credit Exposure (in Millions)	Investment Grade	Total
Gas and electric utilities	$ 96.6	$ 96.9
Energy marketers and traders	238.9	557.2
Financial institutions	31.2	31.2
Other	25.3	25.3
	$ 392.0	$ 710.6
Credit Reserves		(22.8)
Net Credit Exposure from Derivative Contracts		$ 687.8

Fair Value Of Mark-to-Market Derivatives (in Millions)

Period the value of mark-to-market derivatives is expected to be realized:

1-12 months	$ 18.7
13-36 months	(0.3)
37-60 months	(0.4)
61-120 months	(0.6)
121+ months	0.1
Total Fair Value	17.5
Non-Trading MTM Derivatives and SFAS 133 Hedges	291.8
Non-Power Business Unit Hedges	1.9
Total Net Derivative Assets and Liabilities	$ 311.2

Power Portfolio	**Quarter Ended**

(Megawatts)	6/30/06	6/30/05
Owned	207	207
Contracted	8,190	9,012
Total	8,397	9,219

Credit Support (in Millions)

As of June 30, 2006	
Prepays	$ 11
Margins	$ 0
Adequate Assurance	$ 18

Capital Expenditures and Investments
(UNAUDITED)

(Dollars in millions)	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 Year
Capital expenditures:								
Exploration & Production	$ 158.6	$ 182.8	$ 211.1	$ 230.8	$ 783.3	$ 310.3	$ 283.9	$ 594.2
Gas Pipeline:								
Northwest Pipeline	12.0	29.6	43.2	52.2	137.0	40.3	96.0	136.3
Transcontinental Gas Pipe Line	35.7	55.0	80.7	83.1	254.5	46.4	106.7	153.1
Other	—	—	—	2.2	2.2	—	—	—
Total	47.7	84.6	123.9	137.5	393.7	86.7	202.7	289.4
Midstream Gas & Liquids	16.3	25.5	32.7	40.7	115.2	70.7	39.3	110.0
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	1.2
Other	(0.7)*	0.1	1.2	4.0	4.6	—	7.8	7.8
Total	**$ 222.9**	**$ 293.7**	**$ 369.3**	**$ 413.1**	**$ 1,299.0**	**$ 468.3**	**$ 534.3**	**$ 1,002.6**
Purchase of investments:								
Exploration & Production	$ 6.3	$ —	$ 0.3	$ —	$ 6.6	$ —	$ —	$ —
Midstream Gas & Liquids	—	35.0	11.5	—	46.5	(3.4)	0.8	(2.6)
Other	20.0	20.6	4.5	17.9	63.0	13.1	26.0	39.1
Total	**$ 26.3**	**$ 55.6**	**$ 16.3**	**$ 17.9**	**$ 116.1**	**$ 9.7**	**$ 26.8**	**$ 36.5**
Summary:								
Exploration & Production	$ 164.9	$ 182.8	$ 211.4	$ 230.8	$ 789.9	$ 310.3	$ 283.9	$ 594.2
Gas Pipeline	47.7	84.6	123.9	137.5	393.7	86.7	202.7	289.4
Midstream Gas & Liquids	16.3	60.5	44.2	40.7	161.7	67.3	40.1	107.4
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	1.2
Other	19.3	20.7	5.7	21.9	67.6	13.1	33.8	46.9
Total	**$ 249.2**	**$ 349.3**	**$ 385.6**	**$ 431.0**	**$ 1,415.1**	**$ 478.0**	**$ 561.1**	**$ 1,039.1**
Cumulative summary:								
Exploration & Production	$ 164.9	$ 347.7	$ 559.1	$ 789.9	$ 789.9	$ 310.3	$ 594.2	$ 594.2
Gas Pipeline	47.7	132.3	256.2	393.7	393.7	86.7	289.4	289.4
Midstream Gas & Liquids	16.3	76.8	121.0	161.7	161.7	67.3	107.4	107.4
Power	1.0	1.7	2.1	2.2	2.2	0.6	1.2	1.2
Other	19.3	40.0	45.7	67.6	67.6	13.1	46.9	46.9
Total	**$ 249.2**	**$ 598.5**	**$ 984.1**	**$ 1,415.1**	**$ 1,415.1**	**$ 478.0**	**$ 1,039.1**	**$ 1,039.1**

* Reflects the transfer of property from the corporate parent to various segments.

Depreciation, Depletion and Amortization and Other Selected Financial Data
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	2005 *2nd Qtr*	2005 *3rd Qtr*	2005 *4th Qtr*	2005 *Year*	2006 *1st Qtr*	2006 *2nd Qtr*	2006 *Year*
Depreciation, depletion and amortization:								
Exploration & Production	$ 58.6	$ 59.4	$ 66.4	$ 69.8	$ 254.2	$ 73.0	84.2	157.2
Gas Pipeline:								
Northwest Pipeline	17.3	17.0	17.9	18.4	70.6	18.5	18.8	37.3
Transcontinental Gas Pipe Line	49.4	48.6	49.3	49.4	196.7	50.0	51.7	101.7
Total	66.7	65.6	67.2	67.8	267.3	68.5	70.5	139.0
Midstream Gas & Liquids	46.0	46.4	49.5	50.1	192.0	49.4	49.9	99.3
Power	3.9	3.7	3.6	3.7	14.9	3.2	3.2	6.4
Other	3.0	3.0	2.9	2.7	11.6	2.9	2.7	5.6
Total	$ 178.2	$ 178.1	$ 189.6	$ 194.1	$ 740.0	$ 197.0	$ 210.5	$ 407.5
Other selected financial data:								
Cash and cash equivalents	$ 1,210.0	$ 1,297.2	$ 1,360.5	$ 1,597.2	$ 1,597.2	$ 1,115.0	$ 980.4	$ 980.4
Total assets	$ 26,434.1	$ 26,399.7	$ 33,655.8	$ 29,442.6	$ 29,442.6	$ 26,029.0	$ 25,617.2	$ 25,617.2
Capital structure:								
Debt								
Current	$ 99.5	$ 98.6	$ 122.4	$ 122.6	$ 122.6	$ 175.7	$ 170.7	$ 170.7
Noncurrent	$ 7,650.4	$ 7,645.7	$ 7,598.7	$ 7,590.5	$ 7,590.5	$ 7,252.8	$ 7,292.6	$ 7,292.6
Stockholders' equity	$ 5,261.1	$ 5,353.6	$ 5,154.4	$ 5,427.5	$ 5,427.5	$ 5,925.5	$ 5,882.3	$ 5,882.3
Debt to debt-plus-equity ratio	59.6%	59.1%	60.0%	58.7%	58.7%	55.6%	55.9%	55.9%

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**	**$ 113**			**$ 249**	**$ 198**	**$ 66**	**$ (5)**	**$ 168**	**$ 428**
Recurring diluted earnings per common share	**$ 0.23**	**$ 0.19**			**$ 0.42**	**$ 0.33**	**$ 0.11**	**$ (0.01)**	**$ 0.28**	**$ 0.72**
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(43)	38			(5)	(221)	(22)	141	(70)	(172)
Add realized gains/losses from MTM previously recognized	77	100			177	113	77	72	48	310
Total MTM adjustments	34	138			172	(108)	55	213	(22)	138
Tax effect of total MTM adjustments (at 39%)	13	53			66	(42)	21	83	(8)	53
After tax MTM adjustments	21	85			106	(66)	34	130	(14)	85
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 157**	**$ 198**			**$ 355**	**$ 132**	**$ 100**	**$ 125**	**$ 154**	**$ 513**
Recurring diluted earnings per share after MTM adj.	**$ 0.26**	**$ 0.33**			**$ 0.59**	**$ 0.22**	**$ 0.17**	**$ 0.22**	**$ 0.26**	**$ 0.86**
weighted average shares — diluted (thousands)	607,073	595,561			598,634	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.

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.

Exhibit 99.2

Williams 2006
2nd Quarter Earnings

August 3, 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

- Execution of strategy delivers very strong 2Q
- Nearly DOUBLED recurring income after removing mark-to-market effect
- Raising profit guidance for ’06, ’07 and ’08
- 19% jump up in guidance for ’06 key earnings measure*
- Boosting planned capital expenditures to develop reserves
- MLP strategy to accelerate delivery of benefits to Williams

*Recurring income from continuing operations after mark-to-market adjustment

Executing on our strategy to drive near- and long-term value creation

Williams

- Delivering on our promises. So far in 2006, we have:
  - Increased dividend 20%
  - Increased natural gas production nearly 20%
  - Completed $360 million drop-down into Williams Partners
  - Resolved significant legacy issues
- Very strong 2Q results
  - 99% higher recurring results after removing mark-to-market effect
  - Posted nearly $200 million in Midstream recurring segment profit
  - Robust NGL margins more than offset lower natural gas prices
- Well-positioned for continued success
  - Increasing 2006-2008 profit guidance
  - Boosting capital spending to develop reserves
  - Accelerating MLP drop-downs

Well-positioned for continued success:
Accelerating MLP drop-downs

- Pursuing growth with discipline and diligence
  - Successful IPO in August 2005
  - Recently closed $360 million transaction – drop-down of 25.1% of Four Corners gathering and processing assets
  - 21% increase in WPZ unit distribution level since IPO
- Strategy to accelerate delivery of MLP benefits to Williams
  - Goal to drop down $1 billion to $1.5 billion in assets during next 6 months
  - Deep bench of qualifying assets supports annual drop-downs of $1 billion to $2 billion during guidance period
- MLP strategy requires disciplined capital structure
  - WPZ access to debt and equity capital markets is key source of funding to acquire drop-down assets
  - WPZ's debt is consolidated on Williams' balance sheet and the partnership's credit rating is linked to Williams'

Key drivers for our MLP drop-downs

- Ongoing source of lower-cost capital
- WMB's general partnership interest grows in size, value
- Growing source of cash distributions from LP units and general partnership
- Some retained MLP units – cash distributions, value upside

Financial Results

Don Chappel
Chief Financial Officer

Financial Results

Dollars in millions (except per share amounts)	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Income (Loss) from Continuing Operations	($64)	$40	$67	$243
Income (Loss) from Discontinued Operations	(12)	1	(11)	(1)
Net Income (Loss)	($76)	$41	$56	$242
Net Income (Loss) /Share	($0.13)	$0.07	$0.09	$0.41
Recurring Income from Continuing Ops./Share	$0.19	$0.11	$0.42	$0.45
Recurring Income from Continuing Operations After MTM Adjustments/Share	**$0.33**	**$0.17**	**$0.59**	**$0.39**

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 Continuing Operations

Dollars in millions (except per share amounts)	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Income (Loss) from Continuing Operations	($64)	$40	$67	$243
Nonrecurring Items				
Regulatory & Litigation Contingencies/ Settlements and Related Costs	249	13	243	18
Debt Retirement Expense	4	-	31	-
Impairments/Losses/Write-offs	-	53	-	53
(Income)/expense related to prior periods	-	(22)	(6)	(28)
Gain on sale of assets	-	(9)	(7)	(17)
Other – Net	-	1	1	3
Total Nonrecurring items before taxes	253	36	262	29
Tax effect of adjustments	(76)	(10)	(80)	(8)
Recurring Inc. from Continuing Ops. Avail to Com.	$113	$66	$249	$264
Recurring Income from Continuing Ops./Share	$0.19	$0.11	$0.42	$0.45

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)	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Recurring Inc. from Cont. Ops. Avail. to Common	$113	$66	$249	$264
Recurring Diluted Earnings per Common Share	$0.19	$0.11	$0.42	$0.45
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM (gains)/losses	$38	$(22)	$(4)	$(243)
Add realized gains from MTM previously recognized	100	77	177	190
Total MTM Adjustments	138	55	173	(53)
Tax Effect of Total MTM Adjustments	(53)	(21)	(67)	21
After-Tax MTM Adjustments	$85	$34	$106	$(32)
Recurring Inc. from Cont. Ops. Avail. to Common Shareholders after MTM adjustments	$198	$100	$355	$232
Recurring Diluted Earnings Per Share after MTM adjustments	$0.33	$0.17	$0.59	$0.39

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

Financial Results

Second Quarter Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production	$120	$118	$120	$118
Midstream Gas & Liquids	131	109	199	109
Gas Pipeline	123	165	123	143
Power	(80)	(75)	(80)	(62)
Other	(1)	(61)	(1)	(7)
Segment Profit	$293	$256	$361	$301
MTM Adjustments - Power			139	55
Segment Profit after MTM Adjustments			**$500**	**$356**
Memo:				
Power after MTM Adjustments			$59	($7)

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

Financial Results

2006 YTD Segment Profit

Williams

Dollars in millions	Reported		Recurring	
	2006	2005	2006	2005
Exploration & Production	$267	$222	$267	$214
Midstream Gas & Liquids	282	238	344	238
Gas Pipeline	257	332	255	297
Power	(102)	39	(102)	64
Other	1	(65)	1	(12)
Segment Profit	$705	$766	$765	$801
MTM Adjustments - Power			173	(53)
Segment Profit after MTM Adjustments			**$938**	**$748**
Memo:				
Power after MTM Adjustments			$71	$11

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

Segment Profit – Exploration & Production

Dollars in millions	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$120	$118	$267	$222
Nonrecurring				
Gain on sale of assets	-	-	-	(8)
Recurring segment profit	$120	$118	$267	$214

- **2Q06 to 2Q05 financial highlights**:
  - 20% volume production growth
  - $50 million negative hedge impact in 2Q06
  - Operating expense up $0.21/Mfce, $0.09/Mcfe after adjustments for prior periods
  - $0.05 of the $0.09/Mcfe due to production enhancement workover program
- **2006 YTD to 2005 YTD financial highlights**:
  - 18.5% volume production growth
  - 25% recurring segment profit growth
  - $135MM negative hedge impact year to date

Segment Profit - Midstream

Dollars in millions	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$131	$109	$282	$238
Nonrecurring				
Accrual for Gulf Liquids litigation	68	-	68	-
International Contract Settlement	-	-	(6)	-
Recurring segment profit	$199	$109	$344	$238

- **2Q06 to 2Q05 financial highlights:**
  - Record NGL unit margins
  - Higher fee revenue
  - Higher Canadian margins
  - Increased operating expenses
- **2006 YTD to 2005 YTD financial highlights:**
  - Higher NGL unit margins
  - Higher fee revenue
  - Increased operating expenses

Financial Results

Segment Profit – Gas Pipeline

Dollars in millions	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$123	$165	$257	$332
Nonrecurring				
Excess royalty reserve reversal	-	-	(2)	-
Pension expense reduction	-	(17)	-	(17)
Adjustment to carrying value of certain liabilities	-	(5)	-	(18)
Recurring segment profit	$123	$143	$255	$297

- **2Q06 to 2Q05 financial highlights**:
  - Higher:
    - operating expenses
    - pension expense
    - property insurance
  - Partially offset by higher earnings of Gulfstream & other JVs
- **2006 YTD to 2005 YTD financial highlights:**
  - 2006:
    - Higher operating expenses & taxes
  - 2005 recurring income associated with
    - Gulfstream completion fee
    - Operating tax adjustment

Financial Results

Segment Profit - Power

Dollars in millions	2nd Quarter 2006	2nd Quarter 2005	YTD 2006	YTD 2005
Segment Profit/(Loss)	($80)	($75)	($102)	$39
Nonrecurring				
Accrual for regulatory & litigation				
Contingencies/Settlements	-	13	-	17
Expense related to prior periods	-	-	-	8
Recurring segment profit/(loss)	(80)	(62)	(102)	64
MTM Adjustment (Recurring)	138	55	173	(53)
Recurring segment profit/(loss) after MTM Adj.	$59	($7)	$71	$11

- **2Q06 to 2Q05 financial highlights**:
  - Increase in hedged cash flows largely due to benefit of structured hedges and improved power market conditions
  - Increase in natural gas results due to monetizing certain non-core basis positions, partially offset by losses on storage portfolio
- **2006 YTD to 2005 YTD financial highlights**:
  - Increase in hedged cash flows largely due to benefit of structured hedges and improved power market conditions
  - Decrease in expenses (including SG&A) includes $25 million gain related to sale of certain Enron receivables.

Liquidity at June 30, 2006

Dollars in millions

Cash and cash equivalents		$ 980
Other current securities		405
Less:		
Subsidiary and Int'l cash & cash equivalents	$446	
Customer margin deposits payable	32	(478)
Available unrestricted cash		907
Available revolver capacity		1,742
Total Liquidity		**$ 2,649**

2006 Cash Information

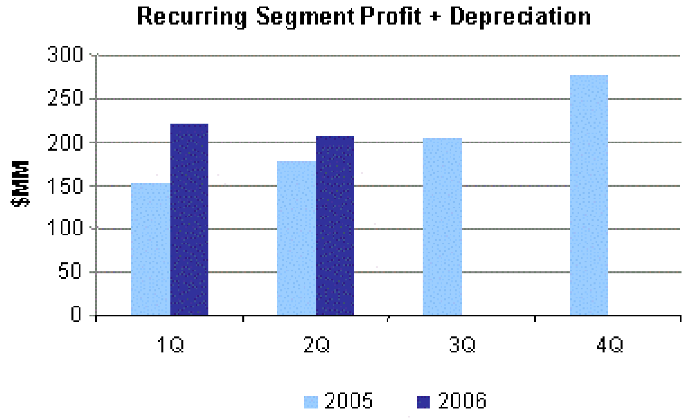
Dollars in millions	**2nd Quarter**	**YTD**
Beginning Unrestricted Cash	**$ 1,115**	**$ 1,597**
Cash flow from Continuing Operations	509	673
Debt retirements	(664)	(728)
Proceeds from debt issuance	699	699
Proceeds from sale of limited partnership units	225	225
Capital expenditures	(534)	(1,003)
Dividends	(54)	(98)
Dividends to minority interests	(10)	(17)
Purchase of auction rate securities	(232)	(327)
Other-net	(74)	(41)
Change in Cash and Cash equivalents	$ (135)	$ (617)
Ending Unrestricted Cash at 6/30/06		**$ 980**
Restricted Cash at 06/30/06 (not included above)		$ 118

Exploration & Production

Ralph Hill
President

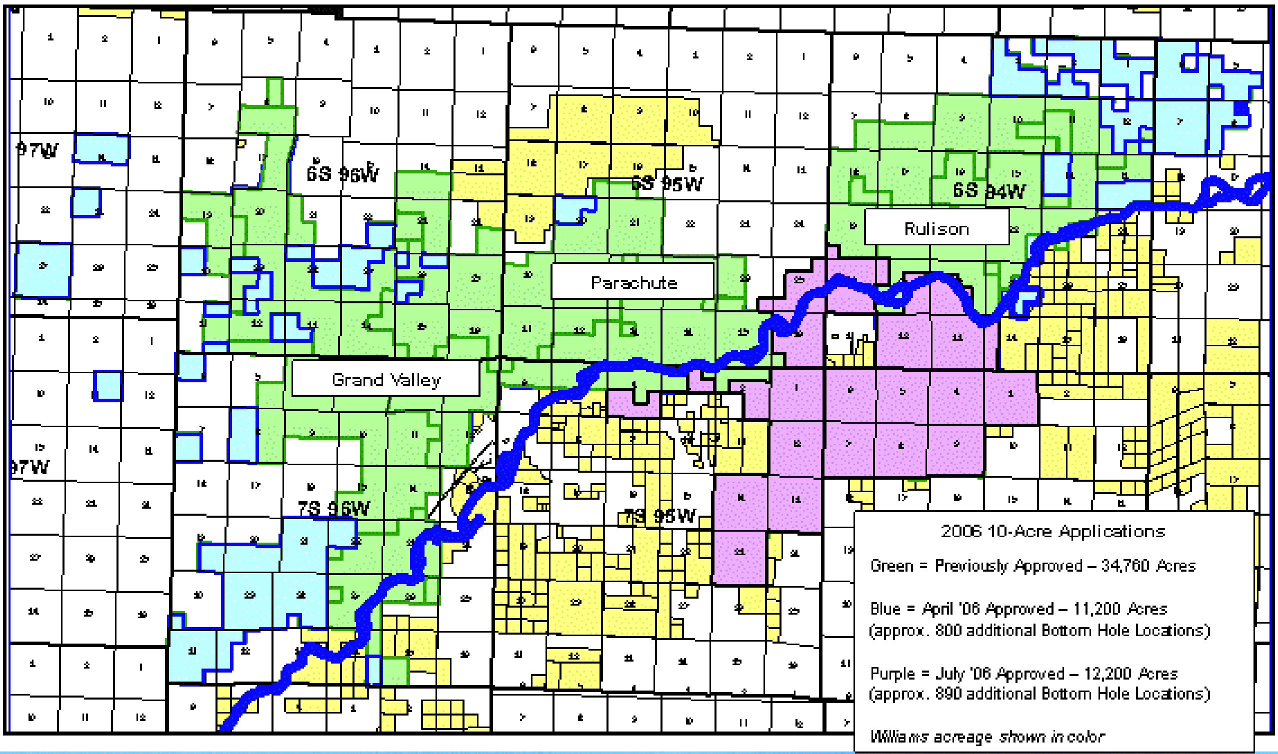
2006 Accomplishments

- 2Q06 production up 20%, 131 MMcfed since 2Q05
- 6 H&P rigs drilling
- Additional 12,200 acres Piceance Valley 10-acre spacing approved
- Piceance Highlands building momentum
- Big George/Powder River volumes continue impressive growth
- Barnett Shale position expanding
- San Juan team awarded Best Management Practices from BLM



2006 10-acre Density Applications Approved

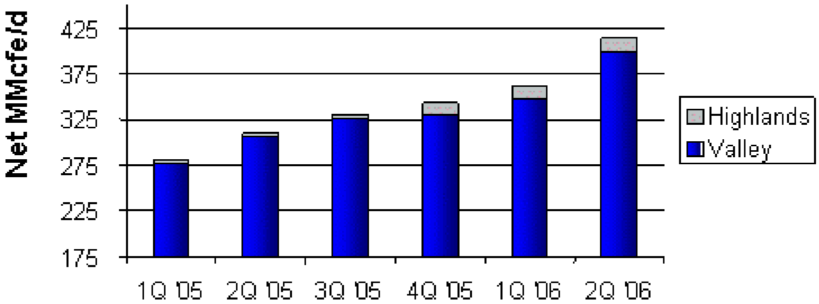
Williams



Piceance Production Growth

- Up 104 MMcfed or 34% over a year ago
- 23 total rigs currently operating in Valley and Highlands compared to 13 a year ago
- 4 additional H&P FlexRigs to be received in 2006
- 4 Nabors Super Sundowner rigs to be received in early 2007
- Williams will be able to high grade rig fleet

Williams' Total Piceance Production

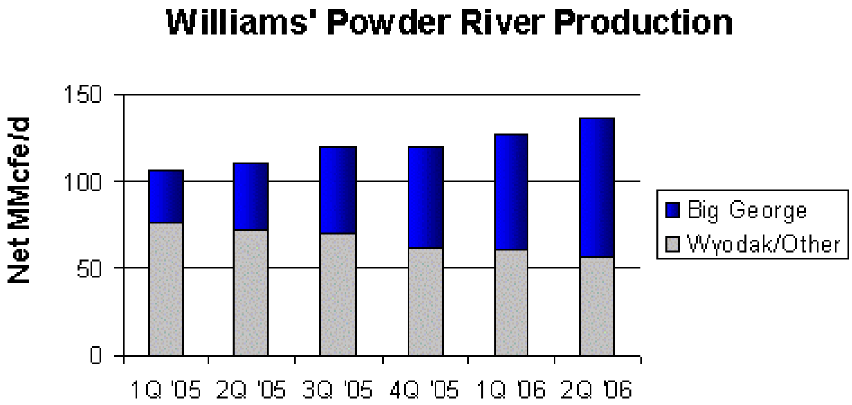


Piceance Highlands – Building Momentum

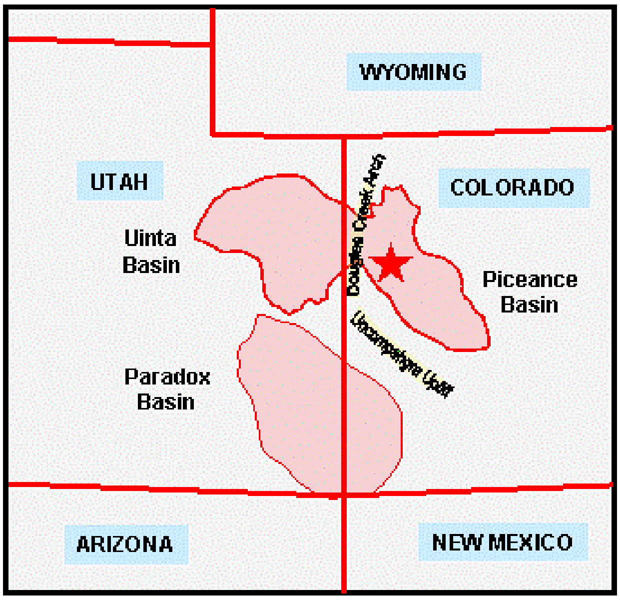
- 44 wells currently producing, up from 8 one year ago
- 13 MMcfed current net production, up 10 MMcfed year over year
- 7 rigs currently operating
- Major road and pipeline infrastructure in progress

Powder River

- Up 26 MMcfed or 23% over a year ago
- Big George coals driving basin growth
  - Up 99% year over year
  - June vs. March volumes up 25%



Pending Piceance Basin Farm-in Opportunity



- Drill-to-earn deal pending
- Targets Williams Fork Formation
- ~11,000 net acres to Williams
- 87.5% NRI
- 600+ potential drill locations
- Williams to operate

New Capital Projects

Dollars in millions	2006		2007		2008	
5/4/06 Capital Guidance	**$950**	**$1,050**	**$950**	**$1,050**	**$1,000**	**$1,150**
New Capital Projects						
Piceance						
Additional Drilling	65		50		70	
Increased Costs	35		30		30	
Gathering & Processing *	40		95		30	
Other Rockies & Barnett Shale Opportunities	60		25		20	
Subtotal	**200**		**200**		**150**	
8/3/06 Capital Guidance	**$1,150**	**$1,250**	**$1,150**	**$1,250**	**$1,150**	**$1,300**

Midpoint Changes	2006	2007	2008
Segment Profit	25	50	75
DD&A	25	30	25
Segment Profit + DD&A	50	80	100
Production (MMcfed)	20	30	40

* Includes 3rd party contracts

Exploration & Production

2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$550 - 650 *525 - 625*	$825 - 950 *775 - 900*	$1,025 - 1,175 *950 - 1,100*
Annual DD&A	360 - 400 *335 - 375*	455 - 505 *425 - 475*	500 - 550 *475 - 525*
Segment Profit + DD&A	$910 - 1,050 *860 - 1,000*	$1,280 - 1,455 *1,200 - 1,375*	$1,525 - 1,725 *1,425 - 1,625*
Capital Spending	$1,150 - 1,250 *950 - 1,050*	$1,150 - 1,250 *950 - 1,050*	$1,150 - 1,300 *1,000 - 1,150*
Production (MMcfe/d)	770 - 845 *750 - 825*	905 - 1,005 *875 - 975*	990 - 1,140 *950 - 1,100*

Unhedged Price Assumption ($/Mcf)			
Average San Juan/Rockies Price	$6.39	$6.09	$6.10
Average Mid-continent Price	$6.55	$6.75	$6.77
NYMEX	$7.84	$7.00	$7.00

Note: 2006-08 hedge information included in Appendix.
Note: If guidance has changed, previous guidance from 5/4/06 is shown in italics directly below.

Key Points – Value Creation Continues

- An industry leader in production growth, cost efficiencies and reserves replacement
- Long-term repeatable drilling inventory of significant proved undeveloped, probables, and possibles
- Strategy remains rapid development of our premier drilling inventory
- Long history of high drilling success, low finding costs
- Short time cycle investments, fast cash returns
- Piceance Highlands significantly contributing
- Experienced and talented work force

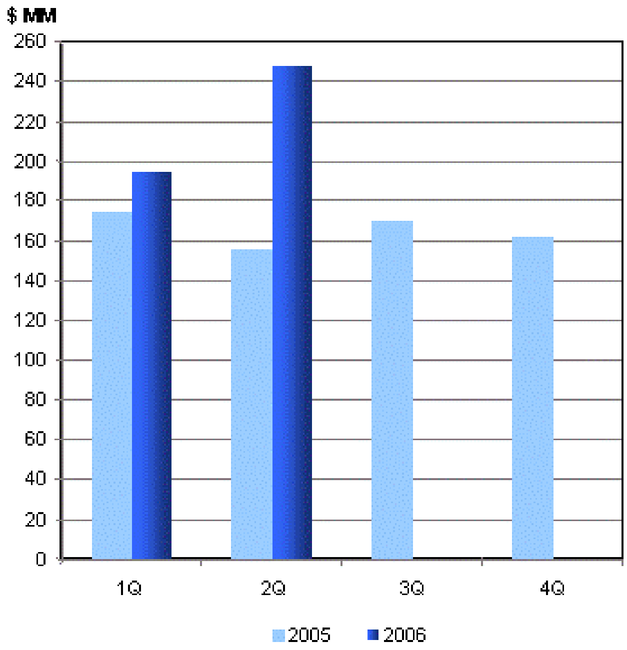
Midstream

Alan Armstrong
President

2006 Accomplishments

- Record quarter
- NGL production rebounding
- NGL unit margins at record levels
- Completed dropdown of 25.1% interest in Four Corners
- Expanding for the future:
  - Opal TXP-IV
  - Opal TXP-V
  - Tahiti lateral
  - Blind Faith
  - Wamsutter gathering

Recurring Segment Profit + Depreciation



Midstream

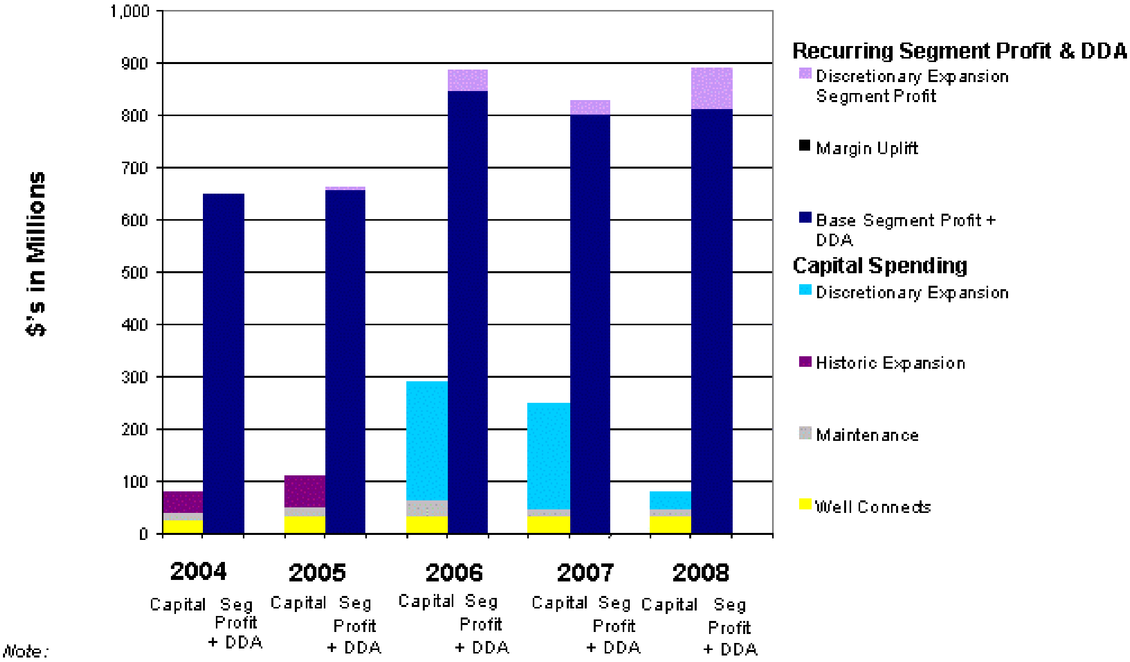
2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$550 - 675 *500 - 600*	$500 - 750 *410 - 530*	$550 - 800 *440 - 580*
Annual DD&A	190 - 200	200 - 210	210 - 220
Segment Profit + DD&A	$740 - 875 *690 - 800*	$700 - 960 *610 - 740*	$760 - 1,020 *650 - 800*
Capital Spending	$280 - 300	$230 - 270	$70 - 90

Un-Hedged Price Assumptions	**2006**		**2007**	**2008**
	1Q-2Q	**3Q-4Q**		
NYMEX Natural Gas ($/Mcf)	**$7.00**	**$7.84**	**$7.00**	**$7.00**
NYMEX Oil ($/bbl)	**$67**	**$62 - $70**	**$55 - $69**	**$55 - $69**
Realized Margin (cents/gallon)	**26.4**			

Note: If guidance has changed, previous guidance from 05/04/2006 is shown in italics directly below.

Free Cash Flow - Forecast



Note:

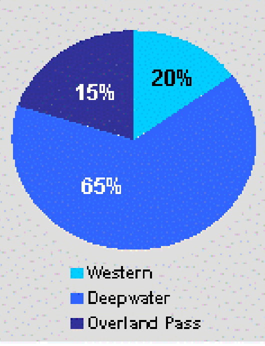
- Segment Profit is stated on a recurring basis. Segment Profit for 2004 has been restated to reflect reclassifications

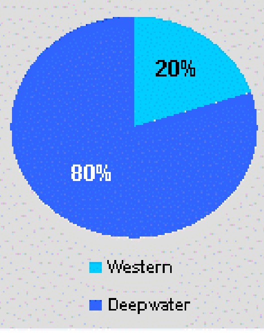
- Segment Profit + DDA and Capital Spending reflect midpoint of ranges.

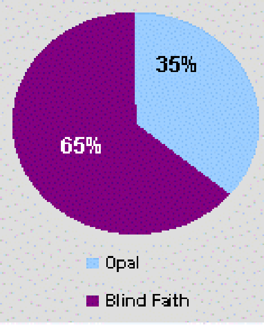
- Margin uplift represents actual realized margin in excess of five year average margin.

Significant Progress Made on Growth Projects

In Development/Proposal 2006 **2007 2008** Spending $500MM–1,500MM	Under Negotiation 2006 **2007 2008** Spending $350MM–550MM	Contracted/Approved **2006 2007** 2008 Spending $280MM
Not in Guidance Western G&P Expansions Deepwater Expansions Overland Pass	Western G&P Expansions ($75MM in guidance) Deepwater Expansions ($30MM in guidance)	***In Guidance*** Blind Faith Opal TXP-V Opal TXP-IV Tahiti Lateral







Key Points

- Focused on our strategy of reliability
- Base business continues to generate healthy returns and free cash flows
- NGL margins exceed historic levels – cushioning enterprise impact of lower gas prices
- Expect NGL margins to remain above historic levels
- Progress continues on deepwater expansions
- Western growth opportunities abound

2006-08 Consolidated Outlook

Don Chappel
Chief Financial Officer

Consolidated

2006 Forecast Guidance

Dollars in millions, except per-share amounts	Aug 3 Guidance	May 4 Guidance
Segment profit before MTM adjustment	$1,355 - $1,675	$1,273 - $1,613
Net Interest Expense	(670) - (710)	(665) - (705)
Other (Primarily General Corp. Costs)	(105) - (125)	(85) - (120)
Securities Litigation Settlement & Related Costs	(162)	-
Pretax Income	418 - 678	523 - 788
Provision for Income Tax	(185) - (295)	(210) - (320)
Income from Continuing Ops	233 - 383	313 - 468
Income/(Loss) from Discontinued Ops	(5) - 0	(5) - 0
Net Income	$228 - 383	$308 - 468
Diluted EPS	$0.37 - $0.63	$0.50 - $0.77
Recurring Income from Cont. Ops	$414 - $564	$318 - $473
Diluted EPS – Recurring	$0.68 - $0.92	$0.52 - $0.78
Diluted EPS – Recurring After MTM Adj. [1]	**$0.95 - $1.20**	**$0.78 - $1.03**

[1] *Includes MTM adjustment of $275 million (pretax) in Aug 3 guidance and $255 million (pretax) in May 4 guidance*
Note: Fully diluted shares of 610 million

Consolidated

2006-08 Segment Profit

Dollars in millions	2006	2007	2008
Exploration & Production	\$550 - 650 *525 - 625*	\$825 - 950 *775 - 900*	\$1,025 - 1,175 *950 - 1,100*
Midstream	550 - 675 [1] *500 - 600*	500 - 750 *410 - 530*	550 - 800 *440 - 580*
Gas Pipeline	475 - 520	585 - 655	590 - 665
Power	(200) - (150) *(205) - (105)*	(175) - (75) *(165) - (15)*	(155) - (5) *(165) - (15)*
Other / Corp. / Rounding	(20) *(22) - (27)*	10 - (30)	(15) - 35
Total Reported Before MTM Adj.	\$1,355 - 1,675 *\$1,273 - 1,613*	\$1,745 - 2,250 *\$1,615 - 2,040*	\$1,995 - 2,670 *\$1,800 - 2,365*
MTM Adjustment	275 *255*	225 *215*	205 *215*
Total Reported After MTM Adj.	\$1,630 - 1,950 *\$1,528 - 1,868*	\$1,970 - 2,475 *\$1,830 - 2,255*	\$2,200 - 2,875 *\$2,015 - 2,580*
Nonrecurring Items	60 *(8)*	-	-
Total Recurring After MTM Adj.	**\$1,690 - 2,010** *\$1,520 - 1,860*	**\$1,970 - 2,475** *\$1,830 - 2,255*	**\$2,200 - 2,875** *\$2,015 - 2,580*

Power After MTM Adj.	\$75 - 125 *\$50 - 150*	\$50 - 150 *\$50 - 200*	\$50 - 200

[1] *Reflects \$68 million of nonrecurring litigation accrual*

Note: If guidance has changed, previous guidance from 5/4/06 is shown in italics directly below

2006-08 Capital Expenditures

Dollars in millions	2006	2007	2008
Exploration & Production	$1,150 - 1,250 *$950 - 1,050*	$1,150 - 1,250 *$950 - 1,050*	$1,150 - 1,300 *$1,000 - 1,150*
Midstream	280 - 300	230 - 270	70 - 90
Gas Pipeline	745 - 815 *710 - 785*	370 - 470 *390 - 490*	340 - 440 *410 - 510*
Power	-	-	-
Other/Corporate	10 - 30	10 - 30	10 - 30
Total	$2,200 - 2,400 *$1,950 - 2,150*	$1,775 - 1,975 *$1,600 - 1,800*	$1,575 - 1,825 *$1,500 - 1,750*

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

Consolidated

2006-08 Outlook

Dollars in millions	2006	2007	2008
Segment Profit			
Reported After MTM Adj.	$1,630 - 1,950 *$1,528 - 1,868*	$ 1,970 - 2,475 *$1,830 - 2,255*	$2,200 - 2,875 *$2,015 - 2,580*
Recurring After MTM Adj.	1,690 - 2,010 *$1,520 - 1,860*	1,970 - 2,475 *$1,830 - 2,255*	2,200 - 2,875 *$2,015 - 2,580*
DD&A	820 - 920 *790 - 890*	930 - 1,030 *900 - 1,000*	1,010 - 1,110 *1,000 - 1,100*
Cash Flow from Ops.[1]	1,500 - 1,800	2,000 - 2,300 *1,850 - 2,150*	2,425 - 2,825 *2,200 - 2,600*
Capital Expenditures	2,200 - 2,400 *1,950 - 2,150*	1,775 - 1,975 *1,600 - 1,800*	1,575 - 1,825 *1,500 - 1,750*
Operating Free Cash Flow[2]	(700) - (600) *(450) - (350)*	225 - 325 *250 - 350*	850 - 1,000 *700 - 850*

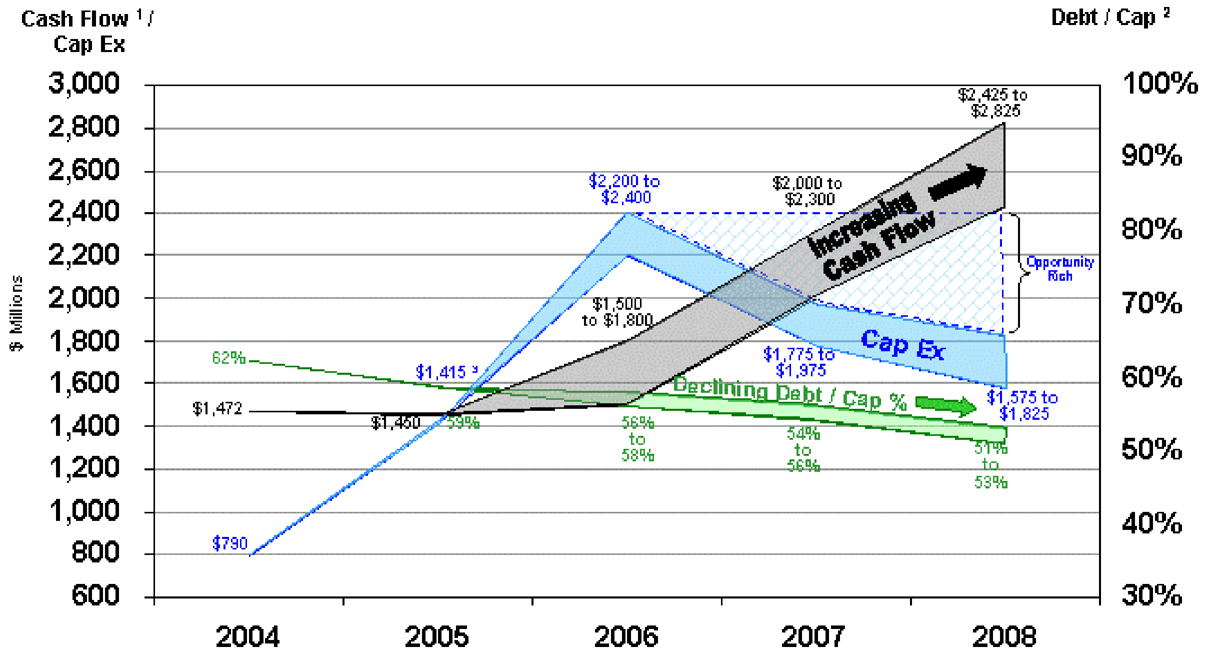
[1] *Cash flow from continuing operations.*
[2] *Operating free cash flow is defined as cash flow from continuing operations less capital expenditures, before dividend or principal payments*

Note: If guidance has changed, previous guidance from 5/4/06 is shown in italics directly below

Consolidated

Strong Operating Cash Flow Growth & Increasing Investment Opportunities

Williams



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

Financial Strategy/Key Points

- Drive/enable sustainable growth in EVA® / shareholder value
- Strategy to accelerate delivery of MLP benfits to WMB
- Continue to maintain and/or improve credit ratios/ratings
- 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

Summary

- Execution of strategy delivers very strong 2Q
- Nearly DOUBLED recurring income after removing mark-to-market effect
- Raising profit guidance for ’06, ’07 and ’08
- 19% jump up in guidance for ’06 key earnings measure*
- Boosting planned capital expenditures to develop reserves
- MLP strategy to accelerate delivery of benefits to Williams

*Recurring income from continuing operations after mark-to-market adjustment

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

[illegible]

Non-GAAP Reconciliation Schedule

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	2006 2nd Qtr	2006 Year
Segment profit (loss):								
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 267.4
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	257.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	282.2
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(102.1)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	0.3
Total segment profit	$ 509.7	$ 256.4	$ 204.5	$ 311.9	$ 1,282.5	$ 412.3	$ 292.9	$ 705.2
Nonrecurring adjustments:								
Exploration & Production	$ (7.6)	$ -	$ (21.7)	$ -	$ (29.3)	$ -	$ -	$ -
Gas Pipeline	(13.1)	(21.7)	(14.2)	37.3	(11.7)	(2.0)	-	(2.0)
Midstream Gas & Liquids	-	-	-	-	-	(6.3)	68.0	61.7
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)	$ 68.0	$ 59.7
Recurring segment profit (loss):								
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	267.4
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	255.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	343.9
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(102.1)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	0.3
Total recurring segment profit	$ 500.4	$ 300.9	$ 169.0	$ 470.0	$ 1,440.3	$ 404.0	$ 360.9	$ 764.9

Note: Segment profit (loss) includes equity earnings (loss) and certain income (loss) from investments reported in Investing income (loss) in the Consolidated Statement of Operations. Equity earnings (loss) results from investments accounted for under the equity method. Income (loss) from investments results from the management of 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	$ 113			$ 249
Recurring diluted earnings per common share	$ 0.22	$ 0.19			$ 0.42
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(43)	38			(5)
Add realized gains/losses from MTM previously recognized	77	100			177
Total MTM adjustments	34	138			172
Tax effect of total MTM adjustments	13	53			66
After tax MTM adjustments	21	85			106
Recurring income from cont ops available to common shareholders after MTM adjust	$ 157	$ 198			$ 355
Recurring diluted earnings per share after MTM adj.	$ 0.26	$ 0.33			$ 0.59
Weighted average shares - diluted (thousands)	607,073	595,561			598,634

	2005				
	1Q	2Q	3Q	4Q	Year
Recurring income from cont ops available to common shareholders	$ 198	$ 66	$ (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	$ 100	$ 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	2Q06	YTD
Net Income (Loss)	$ (76)	$ 56
Loss from Discontinued Operations	12	11
Net Interest Expense	178	337
DD&A	210	408
Provision for Income Taxes	1	89
EBITDA	$ 325	$ 901

Non-GAAP Reconciliation

2Q 2006 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Corp/ Other	Total
Segment Profit (Loss)	$ 120	$ 131	$ 123	$ (80)	$ (1)	**$ 293**
DD&A	84	50	71	3	2	**210**
Segment Profit before DDA	**$ 204**	**$ 181**	**$ 194**	**$ (77)**	**$ 1**	**$ 503**
General corporate expenses						**(34)**
Securities litigation settlement and related costs						**(161)**
Investing income*						**21**
Other income						**(4)**
TOTAL						**$ 325**

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

2006 Forecast EBITDA Reconciliation

Williams

Dollars in millions	Aug 3 Guidance	May 4 Guidance
Net Income	**$228 - 383**	$308 - 468
Loss from Disc. Ops.	5 - 0	5 - 0
Net Interest	670 - 710	665 - 705
DD&A	820 - 920	790 - 890
Provision for Income Taxes	185 - 295	210 - 320
Other/Rounding	(8)	(3) - (8)
EBITDA	**$1,900 - 2,300**	$1,975 - 2,375
MTM Adjustments	275	255
EBITDA - After MTM Adj.	**$2,175 - 2,575**	$2,230 - 2,630

2006 Forecast Segment Contribution

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total
Segment Profit (Loss)	$550 - 650	$550 - 675	$475 - 520	$(200) - (150)	$(20)	$1,355 - 1,675
DD&A	360 - 400	190 - 200	280 - 300	10 - 20	(20) - 0	820 - 920
Segment Profit Before DDA	$910 - 1,050	$740 - 875	$755 - 820	$(190) - (130)	$(40) - (20)	$2,175 - 2,595
Other (Primarily General Corporate Expense & Investing Income)						(105) - (125)
Securities Litigation Settlement and Related Costs						(162)
Rounding						(8)
TOTAL						$1,900 - 2,300

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

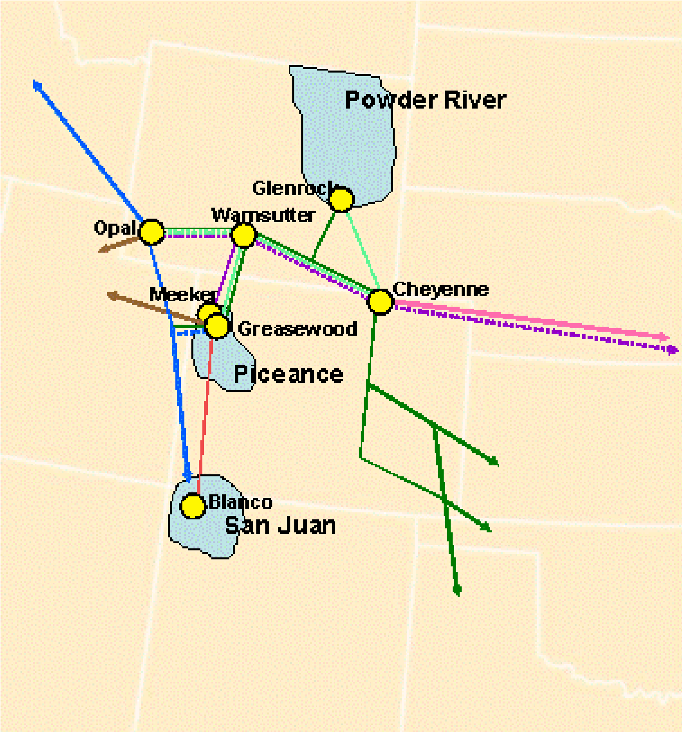
2006 Forecast Guidance Contribution

Williams

Dollars in millions, except per-share amounts	Aug 3 Guidance	May 4 Guidance
Net Income	**$228 - 383**	**$308 - 468**
Less: Discontinued Operations (Loss)	(5) - 0	(5) - 0
Income from Continuing Ops	**$233 - 383**	**$313 - 468**
Non-Recurring Items (Pretax)	261	8
Less Taxes	80	3
Non-Recurring After Tax	181	5
Recurring Income from Cont. Ops	**$414 - 564**	**$318 - 473**
Recurring EPS	**$0.68 - $0.92**	**$0.52 - $0.78**
Mark-to-Market Adjustment (Pretax)	275	255
Less Taxes @ 39%	107	99
Mark-to-Market Adjust. After Tax	168	156
Inc. from Cont. Ops after MTM Adj.	**$582 - 732**	**$474 - 629**
Inc. from Cont. Ops after MTM Adj. EPS	**$0.95 - $1.20**	**$0.78 - $1.03**

Appendix

Rockies Producer Not Rockies Price Taker



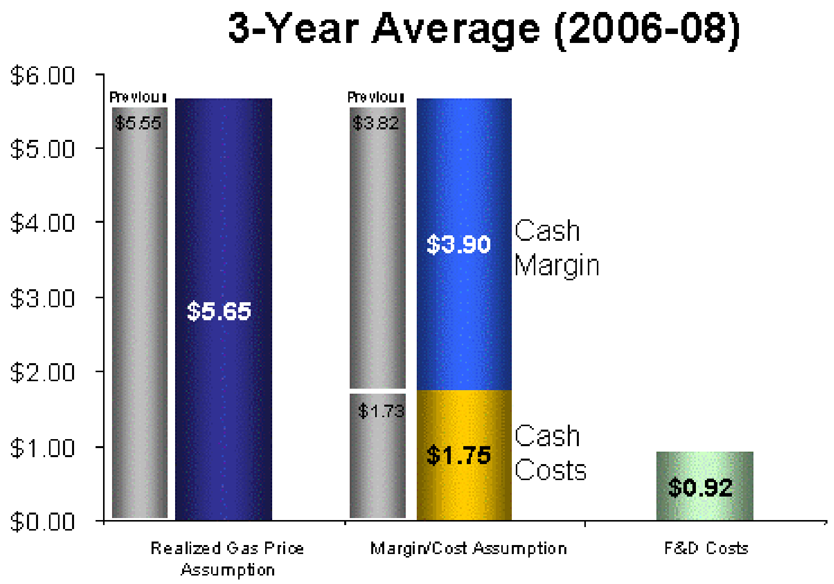
Pipes Used to Move Williams

- 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

Cash Margin Analysis



Reflective of core basins

- *$5.65 is after hedging and includes average basin market price of $6.41 before hedging*
- *Cash costs include LOE, G&A, taxes and gathering*
- *F&D costs include acquisition and development expenditures/proved reserves ('03-'05 average)*

2Q Net Realized Price Summary

	2Q '06	
	Unhedged	Hedge
Market Price:		
NYMEX including collars	$6.90 - $7.20	4.53
Basis Differential	(1.40 - 1.60)	(0.57)
Net basin market price	$5.30 - $5.80	$3.96
Net basin market price	**$5.30 - $5.80**	**$3.96**
Fuel & Shrinkage/Gathering/ Transportation	(0.60 - 0.80)	(0.50 - 0.60)
Net Price	**$4.50 - $5.20**	**$3.36 - $3.46**
Quarter Volume Totals	(qtr daily volumes - qtr daily volumes) x (91/1000)	(qtr daily hedge volumes) x (91/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

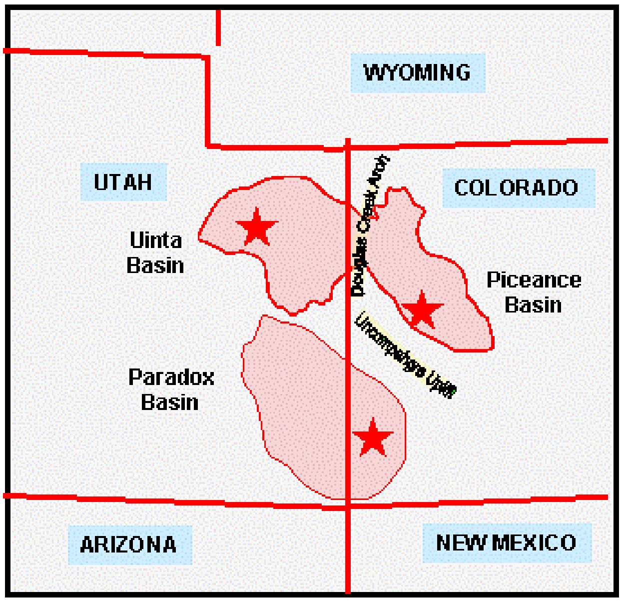
2006-08 Hedge Update

Dollars in millions

	3Q-4Q 2006	2007	2008
Fixed Price at the basin:			
Volume (MMcf/d)	297	172	73
Average Price ($/Mcf)	$3.84	$3.90	$3.96
NYMEX Collars:			
Volume (MMcf/d)	64	15	-
Average Price ($/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*

E&P Opportunities – Previously Announced



- **Piceance Basin: Shale Ridge Prospect (Dakota Sandstone play)**
  - Leased 13,904 gross/net acres
  - 100% WI; 87.5% NRI
  - 10-year lease term
- **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

Piceance Highlands – Results to Date

Project Area	Wells Drilled and Completed	Average 30 Day Rate/Completed Well (MMcfed)	Expected EUR* Range (Bcfe/well)
Trail Ridge	18	1.2	1.2 – 1.8
West Grand Valley	2	1.3	1.2 – 1.8
Ryan Gulch	14	1.2	1.2 – 2.0
Allen Point	6	1.2	1.2 – 1.6

*** Estimated Ultimate Recovery**

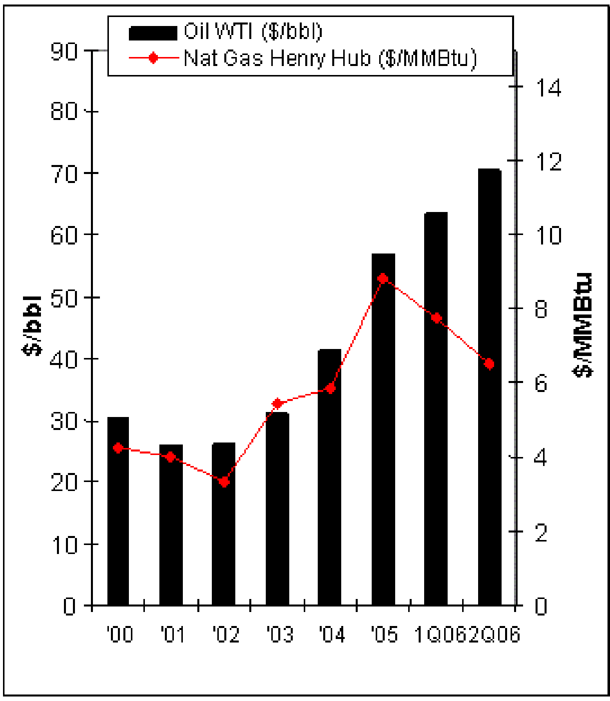
Piceance Highlands Project Summary

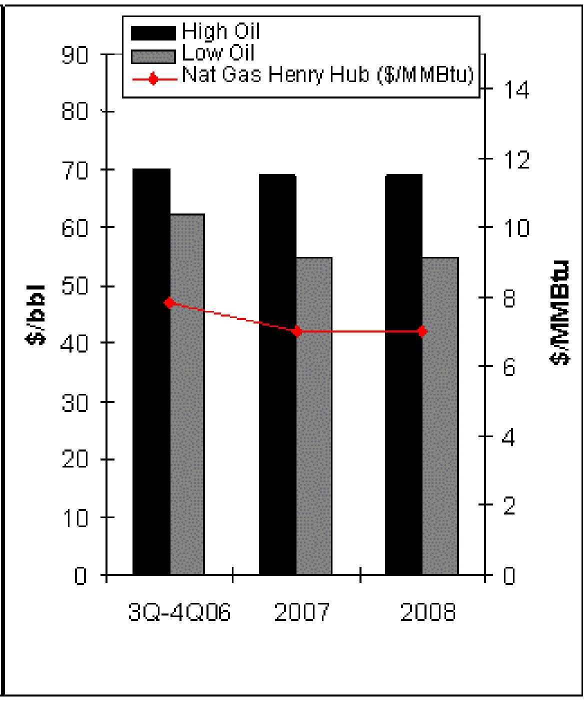
Project Area	Net Acres	Estimated Gross Potential Locations	Estimated Net Potential Reserves (Bcfe)	2004 Wells	2005 Wells	Projected 2006 Wells
Trail Ridge (10-acre density)	21,512	1,500	1,500-2,000	3	12	20
West Grand Valley (10-acre density)	1,080	90	80	1	1	0
Ryan Gulch (40-acre density)	16,078	800	700	3	5	22*
Allen Point (40-acre density)	6,240	200	140	0	6	9
Total	**44,910**	**2,590**	**2,420-2,920**	**7**	**24**	**51**

*** 3 wells non-operated**

Midstream

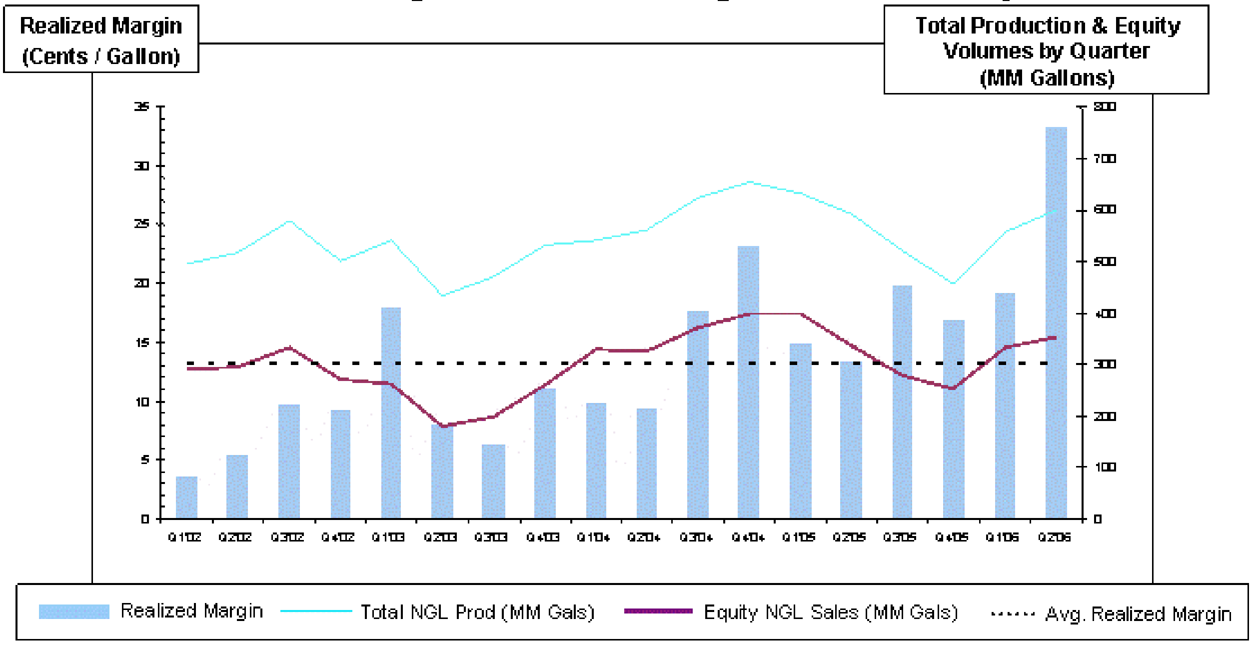
Pricing Assumptions Included in Guidance





Margins Above Average

Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Actual realized margins, does not include Discovery volumes. Five year average of 13.2 cpg is calculated for the period 3Q01-2Q06.

2006 Accomplishments

Northwest:

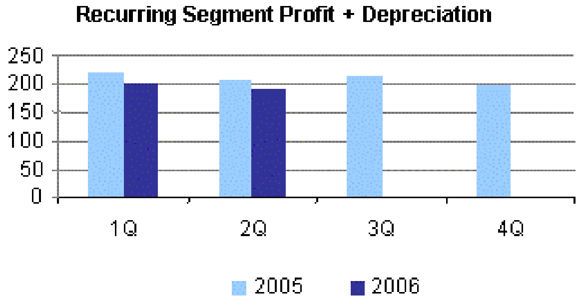
- Filed rate case on June 30, 2006. The anticipated effective date is January 1, 2007
- Open season begins for long-term firm transportation service for Greasewood Lateral expansion
- FERC certificate application filed for Jackson Prairie Expansion
- Completed $175 million offering of senior unsecured notes due 2016

Transco:

- Leidy to Long Island Expansion project receives FERC approval
- FERC certificate application filed for Potomac Expansion
- Completed $200 million offering of senior unsecured notes due 2016

Gulfstream:

- Executed agreement with Progress Energy to provide 155 MDth/d to its Bartow Power Plant with the Gulfstream Phase IV expansion project



2006-08 Guidance

Williams

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	$745 - 815 *710 - 785*	$370 - 470 *390 - 490*	$340 - 440 *410 - 510*

Note: If guidance has changed, previous guidance from 05/04/06 is shown in italics directly below.

2006-08 Capital Spending Detail

Dollars in millions	2006	2007	2008
Normal Maintenance/Compliance	$375 - 435 *340 - 405*	$210 - 265	$180 - 260
Northwest 26-inch Replacement	276	2	-
Expansion[1]	95 - 105	160 - 200 *180 - 220*	160 - 180 *230 - 250*
Total	$745 - 815 *710 - 785*	$370 - 470 *390 - 490*	$340 - 440 *410 - 510*

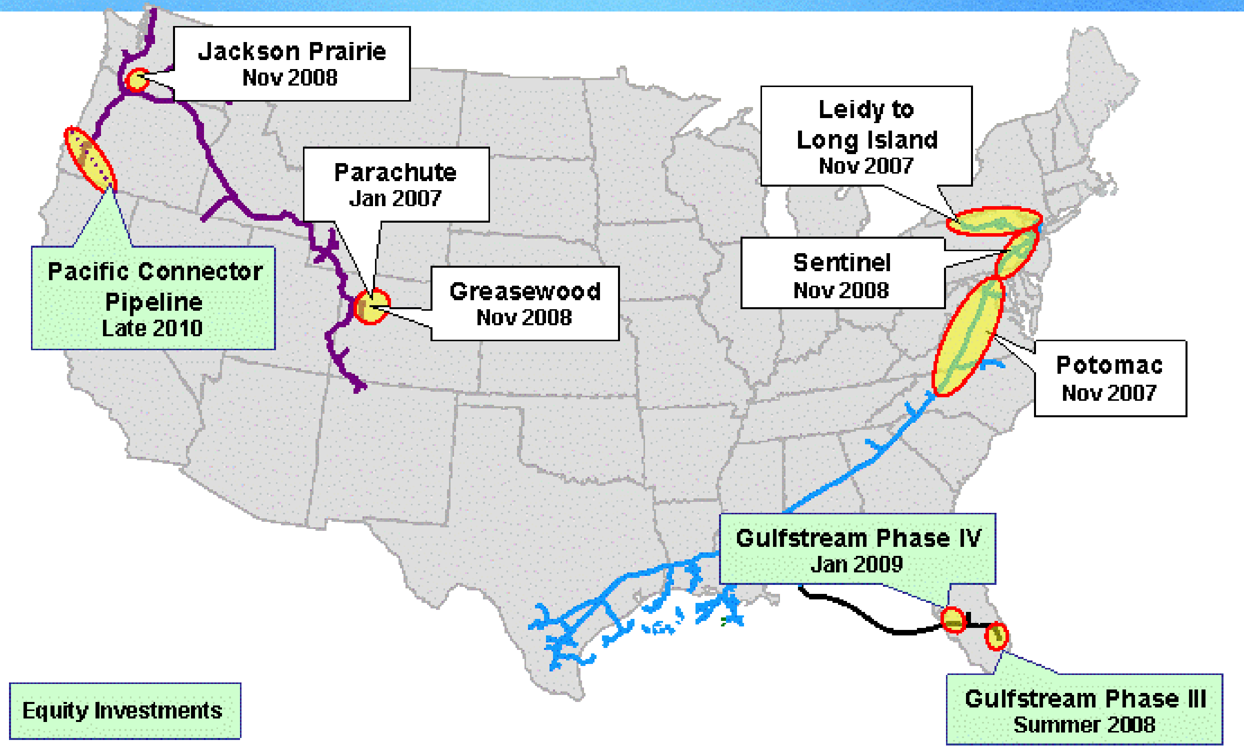
[1]Major Growth Projects (in guidance):	2006	2007	2008	1st full yr Seg. Profit
Parachute (In Service 1/07)	$55 - 65			$9
Leidy to Long Island (In Service11/07)	10 - 15	$85 - 100	$1 - 5	20
Potomac (In Service 11/07)	5 - 10	55 - 65	1 - 5	11
Sentinel (In Service 11/08)	1 - 5	5 - 15	110 - 130	22
Greasewood (In Service 11/08)			25 - 30	5

Note: If guidance has changed, previous guidance from 05/04/06 is shown in italics directly below.

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

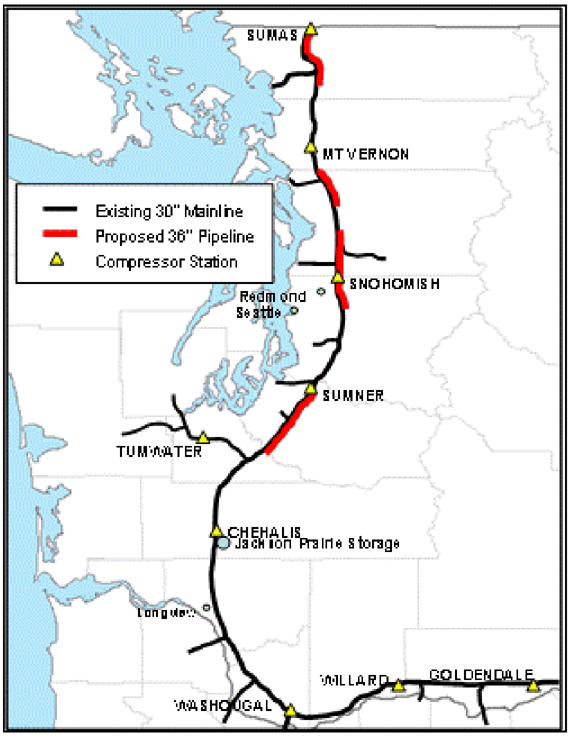
Gas Pipeline

Growth Projects and Opportunities Update



Capacity Replacement Project on Track

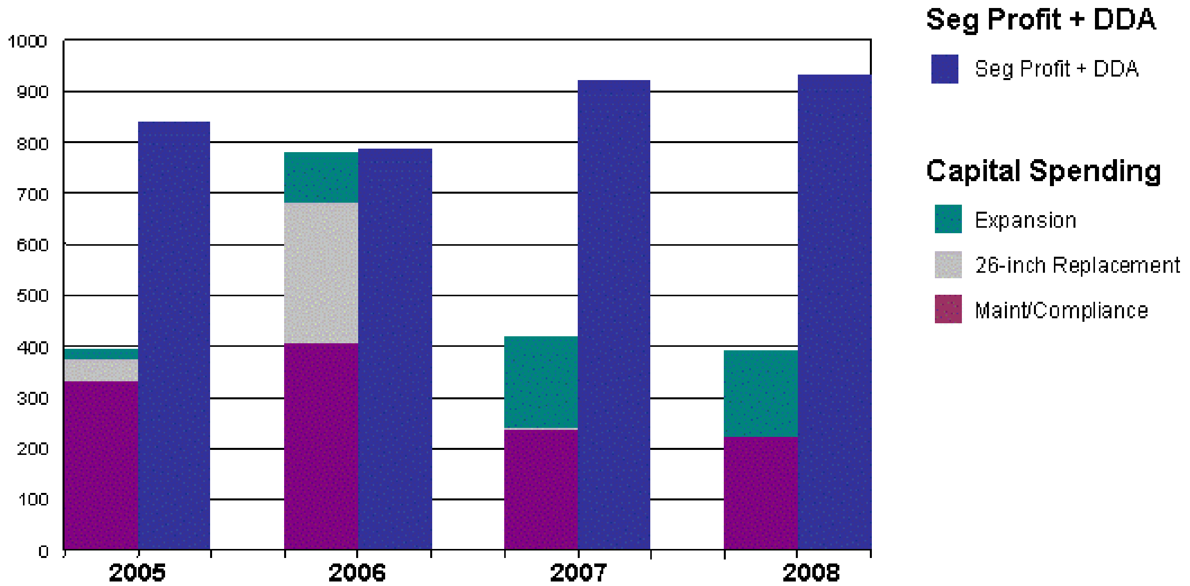
- **Design – 360 MMcfd**
- **Scope of Work**
  - Approx. 80 miles of 36" pipeline
  - 10,760 net horsepower added
  - Station Modifications
  - 268 miles of 26" pipeline retired
- **Capital Costs on target - $333 MM**
- **Schedule**
  - ✓ FERC Certificate – 9/2005
  - ✓ Start HDD – 10/2005
  - ✓ Sta. & P/L Mobilized – 5/2006
  - Construction – Summer 2006
  - In-service – 11/ 2006 (In rates – 1/2007)



Key Points

- 26-inch Replacement on target to be in-service November 1st
- Growth projects progressing
- Rate Case filings continue on target
  - Northwest filed Jun 30th, effective Jan 1st
  - Transco to file Aug 31st, effective Mar 1st

Long-term Free Cash Flow



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

2006-08 Guidance

Dollars in millions	2006	2007	2008
Prior Guidance - Segment Loss before MTM Adj	($205) - (105)	($165) - (15)	($165) - (15)
Est. Fwd Impact of 2Q06 MTM Earnings and other portolio adjustments	$5 - (45)	($10) - (60)	$10 - 10
New Guidance - Segment Loss before MTM Adj	($200) - (150)	($175) - (75)	($155) - (5)
	($205) - (105)	*($165) - (15)*	*($165) - (15)*
Estimated MTM Adjustments	275	225	205
	255	*215*	*215*
Segment Profit after MTM Adj	75 - 125	50 - 150	50 - 200
Recurring Segment Profit after MTM Adj	**$75 - 125**	**$50 - 150**	**$50 - 200**
	$50 - 150	*$50 - 200*	
Capital Expenditures	-	-	-

Note: If guidance has changed, previous guidance from 5/04/06 is shown in italics directly below.

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

Dollars in Millions	Commodity Power & NG	Working Capital/ Other	Total
Segment Loss	($88)	($14)	($102)
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(4)		(4)
Add Realized Gains from MTM Previously Recognized	177		177
Segment Profit/(Loss) After MTM Adjustments	85	(14)	71
Total Working Capital Change[1,2&3]		(324)	(324)
Power Segment CFFO	**$85**	**($338)**	**($253)**

[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.

[3]CFFO includes cash margin dollars sent out on behalf of other business units.

Power Portfolio Cash Flow Analysis

Estimated undiscounted dollars in millions

Power Portfolio *Actual vs. Forecast 2006*	2Q06A	2Q06F	QTD Variance	YTD06A	YTD06F	YTD Variance	2006A+F	2007F	2008F
Tolling Demand Payment Obligations	($96)	($99)	$3	($182)	($185)	$3	($397)	($406)	($412)
Hedged Cash Flows [2]	151 [1]	160	(9)	282 [1]	296	(14)	576	476	496
Merchant Cash Flows [3]							31	89	78
SG&A and Other [4]	(20)	(21)	1	(19)	(42)	23	(64)	(85)	(80)
Total Power Portfolio Cash Flows	**$35**	**$40**	**($5)**	**$81**	**$69**	**$12**	**$146**	**$74**	**$82**
Working Capital & Other [5]	(288)	n/a		(334)	n/a		n/a	n/a	n/a
Estimated Power Segment Cash Flows	($253)			($253)					

[1] Q206 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities. Q206 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 YTD 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 reasonable estimable.

Note: Q206 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 6/30/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

2Q06 Financial Statement Changes for Derivatives

During 2Q06, Williams reported the following changes related to its derivative portfolio:

Dollars in millions	Balance Sheet		Income Statement	
	Der A/L	OCI	MTM Gain/(Loss)	Realized (Gain)/Loss
Total Change in Consolidated Derivative Values [1]	($60)	$45	($33)	($72)
Less change in Option Premiums/Prudency/Other	(1)			(1)
Remaining Change in Consolidated Derivative Values	($59)	$45	($33)	($71)
Change in E&P Hedge Values	135	86	6	
- Prior MTM Realized (Ineffectiveness)				(7)
- OCI Realized				50
Change in Midstream Hedge Values	(21)	(21)		
- Prior MTM Realized			(0)	
- OCI Realized				(0)
Change in Power Hedge Values	(173)	(20)	(39)	
- Prior MTM Realized				(100)
- OCI Realized				(14)

- The net change in Derivative Assets and Liabilities for E&P was positive reflecting the 2Q06 decrease in gas prices against a short derivative position
- The net change in Derivative Assets and Liabilities for Midstream was negative reflecting the 2Q06 price increase on crude and NGL's against a short derivative position
- The net change in Derivative Assets and Liabilities for Power was negative, reflecting the 2Q06 decrease in gas prices against a long derivative position

[1] 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 6/30/06*	Q206A	Q206F	QTD Variance	2006F+A	2007F	2008F
Tolling Demand Payment Obligations	($38)	($38)	$0	($154)	($157)	($159)
Hedged Cash Flows[2]	117[1]	106	11	439	376	355
Merchant Cash Flows[3]				(3)	9	9
Total Cash Flows	$79	$68	$11	$282	$228	$205
Capacity Available (in MW)				3,805	3,805	3,805
Total Capacity Sold				2,772	3,329	3,452
Remaining Available (in MW) after all hedges				1,033	476	353

1 Q206 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: Q206 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 6/30/06. 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 6/30/06*	Q206A	Q206F	QTD Variance	2006F+A	2007F	2008F
Tolling Demand Payment Obligations	($21)	($22)	$1	($88)	($89)	($90)
Hedged Cash Flows[2]	9 [1]	11	(2)	49 [1]	37	49
Merchant Cash Flows[3]					22	9
Total Cash Flows	($12)	($11)	($1)	($39)	($30)	($32)
Capacity Available (in MW)				1,303	1,303	1,303
Total Capacity Sold				401	346	365
Remaining Available (in MW) after all hedges				902	957	938

[1] Q206 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: Q206 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 6/30/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Power

East Undiscounted Cash Flows

Dollars in millions

East Power Portfolio *Estimated as of 6/30/06*	Q206A	Q206F	QTD Variance	2006F+A	2007F	2008F
Tolling Demand Payment Obligations	($36)	($39)	$3	($155)	($160)	($162)
Hedged Cash Flows[2]	25[1]	42	(17)	123[1]	63	90
Merchant Cash Flows[3]					59	60
Total Cash Flows	($12)	$2	($14)	($32)	($38)	($12)
Capacity Available (in MW)				2,280	2,280	2,280
Total Capacity Sold				1,561	631	583
Remaining Available (in MW) after all hedges				719	1,649	1,697

[1] Q206 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: Q206 Forecast estimated as of 12/31/05. 2007 forward forecast estimated as of 6/30/06. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

WMB Collateral Outstanding

Williams

	As of 6/30/06				
Dollars in millions	**E&P**	**Midstream**	**Power**	**Corp./ Other**	**Total**
Margins & Ad. Assur.	$224	$0	$18	$0	$242
Prepayments	0	0	11	0	11
Subtotal	224	0	29	0	253
Letters of Credit	387	109	397	65	958
Total as of 6/30/06	$611	$109	$426	$65	$1211
Total as of 12/31/05	746	243	343	91	1423
Change	($135)	($134)	$83	($26)	($212)

WMB Collateral Sensitivity

Dollars in millions

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

Days	6/30/2006	3/31/2006	12/30/2005	9/30/2005
30	($246)	($223)	($325)	($469)
180	($580)	($769)	($559)	($868)
360	($489)	($626)	($567)	($926)

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

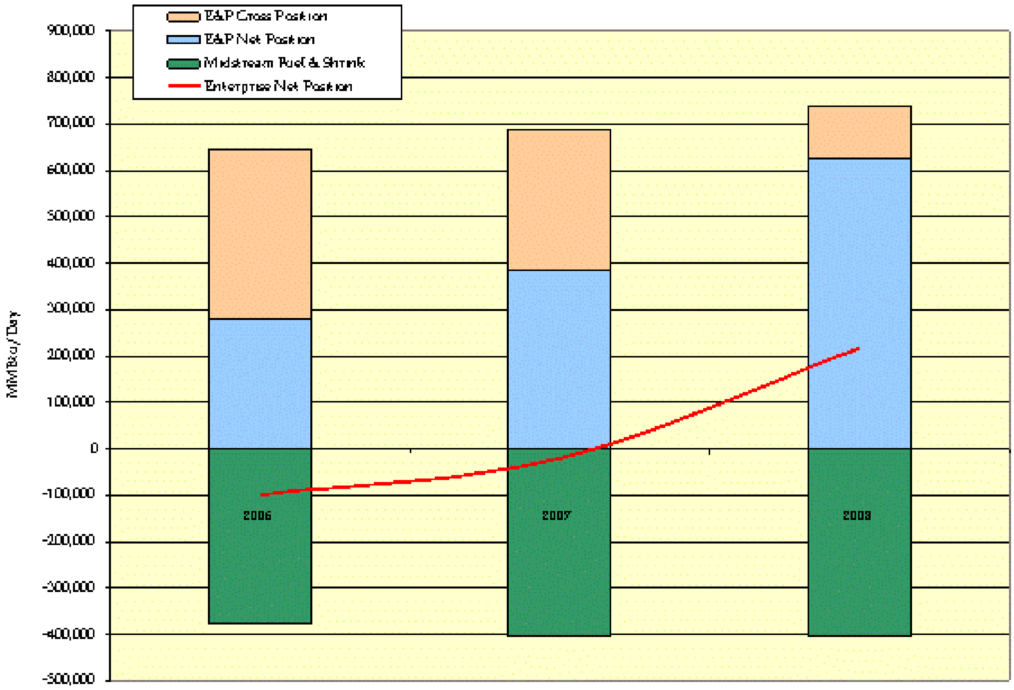
Sensitivity Analysis

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	$0-$2 MM	$0-$2 MM	$3-$8 MM
2007	$6-$9 MM	$3.5-$5.5 MM	$11-$16 MM
2008	$25-$28 MM	$6-$8 MM	$10-$15 MM

[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 six month impact, 2007-2008 metrics reflect a full twelve month imact

Natural Gas Outright Position



Consolidated

Debt Balance[1]

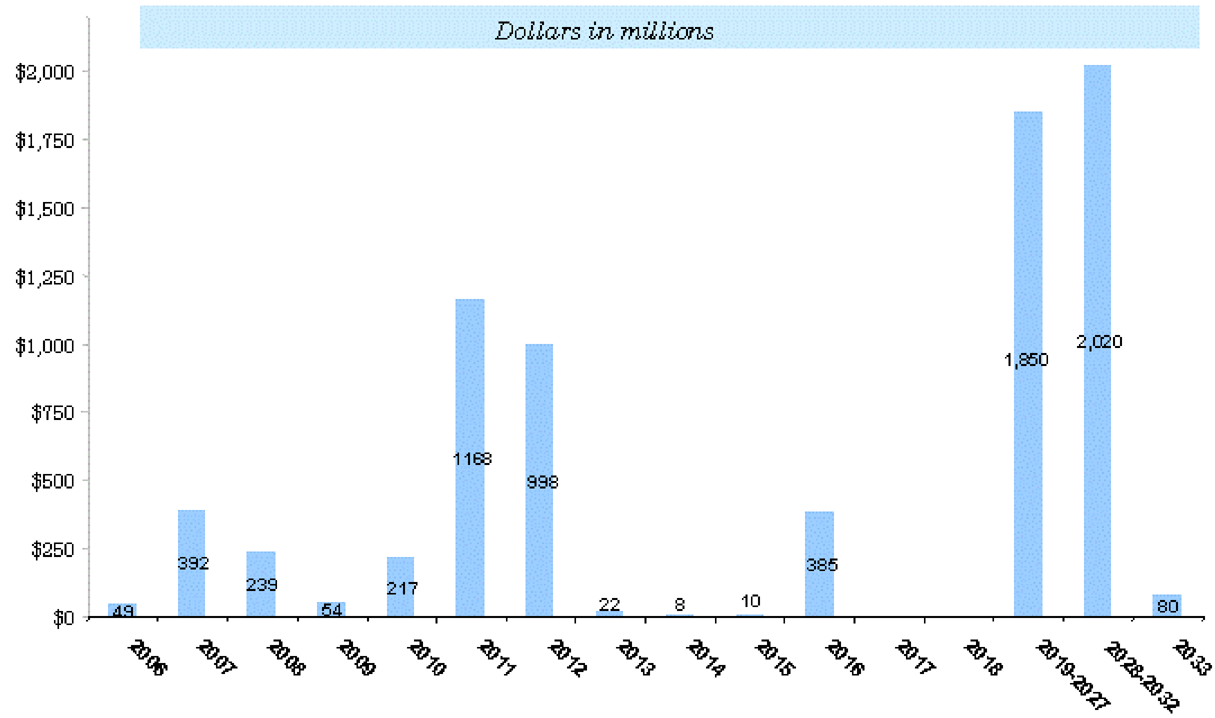
Dollars in millions

		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%**
Additions	699	
Early Retirements	(485)	
Scheduled Debt Retirements & Amortization	(180)	
Debt Balance @ 6/30/06	**$7,463**	**7.7%**
Fixed Rate Debt @ 06/30/06	**$7,309**	**7.7%**
Variable Rate Debt @ 06/30/06	**$154**	**6.1%**

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

Consolidated

Debt Amortization – As of 6/30/2006



Consolidated

EPS Metrics

2006	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	($.11)	-	-	$0.11
Recurring EPS	0.23	0.19	-	-	0.42
Recurring EPS after MTM Adj.	**0.26**	**0.33**	-	-	**0.59**
Average Shares (MM)	607	596	-	-	599

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

2006 Interest Expense Forecast Guidance

Dollars in millions	2006
Interest on Long-Term Debt	$570 - $590
Amortization Discount/Premium and other Debt Expense	25 - 30
Credit Facilities: (incl. Commitment Fees plus LC Usage)	40 - 50
Interest on other Liabilities	43 - 53
Interest Expense	$678 - $723
Less: Capitalized Interest	(8) - (13)
Net Interest Expense Guidance	**$670 - $710**

Consolidated

2006 Effective Tax Rates

	2006					
	First Quarter		Second Quarter		Year-to-Date	
Statutory Rate	77	35%	(22)	35%	55	35%
State	10	5%	(1)	1%	9	6%
Foreign	0	0%	7	-10%	7	4%
Nondeductible Expenses *(Shareholder Litigation/Convertible Debentures)*	0	0%	18	-28%	18	12%
Other	1	0%	(1)	1%	0	0%
Tax Provision/(Benefit)	88	40%	1	-1%	89	57%

	2006	2007	2008
Effective Tax Rate Guidance [1]	39%	39%	39%
Cash Tax Rate Guidance [2]	10-15%	5-10%	9-14%

Note 1: Additional income tax expense of $25-35 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.