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

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported): November 2, 2006

The Williams Companies, Inc.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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Item 2.02. Results of Operations and Financial Condition.

On November 2, 2006, The Williams Companies, Inc. ("Williams" or the "Company") issued a press release announcing its financial results for the quarter ended September 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 November 2, 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) None

(d) Exhibits

Exhibit 99.1 Copy of Williams' press release dated November 2, 2006, and its accompanying highlights and reconciliation schedules, publicly announcing its third quarter 2006 financial results.

Exhibit 99.2 Copy of Williams' slide presentation to be utilized during the November 2, 2006, public conference call and webcast.

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

THE WILLIAMS COMPANIES, INC.

Date: November 2, 2006

/s/ Donald R. Chappel

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

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
Exhibit 99.1	Copy of Williams' press release dated November 2, 2006, and its accompanying highlights and reconciliation schedules, publicly announcing its third quarter 2006 financial results.
Exhibit 99.2	Copy of Williams' slide presentation to be utilized during the November 2, 2006, public conference call and webcast.

Exhibit 99.1

News Release

NYSE: WMB

Date: Nov. 2, 2006

Williams Reports Third-Quarter 2006 Financial Results

- *3Q Net Income Up Significantly*
- *Company Raises Earnings Guidance Again for 2006*
- *38% Increase in 3Q Recurring Adjusted Income; 48% Increase YTD by Same Measure*
- *Natural Gas Production Up 22%; Surpasses 800 MMcfe Per Day*
- *NGL Margins 112% Higher Than 3Q 2005*

Quarterly Summary Information	3Q 2006		3Q 2005	
Per share amounts are reported on a diluted basis	millions	per share	millions	per share
Income from continuing operations	$ 110.1	$ 0.19	$ 5.7	$ 0.01
Loss from discontinued operations	$ (3.9)	$ (0.01)	$ (1.3)	$ 0.00
Net income	$ 106.2	$ 0.18	$ 4.4	$ 0.01
Recurring income (loss) from continuing operations*	$ 113.4	$ 0.19	$ (4.6)	$ (0.01)
After-tax mark-to-market adjustments	$ 59.0	$ 0.09	$ 129.9	$ 0.23
Recurring income from continuing operations — after mark-to-market adjustment*	$ 172.4	$ 0.28	$ 125.3	$ 0.22

TULSA, Okla. — Williams (NYSE:WMB) today announced third-quarter 2006 unaudited net income of $106.2 million, or 18 cents per share on a diluted basis, compared with net income of $4.4 million, or 1 cent per share, for third-quarter 2005.

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	$ 177.3	$ 0.29	$ 248.6	$ 0.42
Loss from discontinued operations	$ (15.2)	$ (0.02)	$ (1.8)	$ 0.00
Net income	$ 162.1	$ 0.27	$ 246.8	$ 0.42
Recurring income from continuing operations*	$ 361.9	$ 0.60	$ 259.7	$ 0.44
After-tax mark-to-market adjustments	$ 165.5	$ 0.27	$ 97.6	$ 0.16
Recurring income from continuing operations — after mark-to-market adjustment*	$ 527.4	$ 0.87	$ 357.3	$ 0.60

* 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.

Third-quarter 2006 benefited from a 112 percent increase in natural gas liquids (NGL) sales margins, 22 percent higher natural gas production volumes, and significantly lower levels of forward unrealized mark-to-market losses. These benefits were partially offset by higher operating and maintenance costs.

Year-to-date through Sept. 30, Williams reported net income of $162.1 million, or 27 cents per share on a diluted basis, compared with net income of $246.8 million, or 42 cents per share, for the same period in 2005.

Results for the first nine months of 2006 are significantly reduced by the after-tax impact of legacy litigation charges recorded in the second quarter totaling approximately $175 million.

While these nonrecurring charges obscure the company's strong performance overall in 2006, Williams has realized significantly higher NGL sales margins and continues to rapidly increase its natural gas production in the western United States. Production in the Piceance Basin – the company's cornerstone property for production growth – increased 31 percent year-over-year in the third quarter.

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 derivatives – increased 38 percent from a year ago to $172.4 million, or 28 cents per share, in third-quarter 2006 from $125.3 million, or 22 cents per share in third-quarter 2005.

Year-to-date through Sept. 30, recurring income from continuing operations – adjusted to remove the effect of mark-to-market accounting – was $527.4 million, or 87 cents per share, an increase of 48 percent compared with $357.3 million, or 60 cents per share, for the same period in 2005.

The quarterly and year-to-date improvement is primarily the result of higher NGL sales margins; increased natural gas production, particularly in the Piceance and Powder River basins; increased gathering and processing revenue; and improved results in the power portfolio.

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 Again

Williams has raised its guidance for 2006 based on the company's strong operating performance through three quarters, anticipated increases in natural gas production volumes, and its outlook for energy commodity prices — key factors that have driven higher sales margins for natural gas liquids.

The company now expects $1.05 to $1.20 for diluted earnings per share in 2006 on a recurring basis adjusted to remove the effect of mark-to-market accounting, compared with the previous expectation of 95 cents to $1.20.

Williams also is raising its expectations for 2006 consolidated segment profit on a recurring basis adjusted to remove the effect of mark-to-market accounting. The company now expects approximately $1.8 billion to $2.02 billion for this measure. Williams previously expected $1.69 billion to $2.01 billion.

Williams also modified its expected capital budget for 2006 through 2008. The increase in planned capital spending for 2007 and 2008 is for Midstream growth projects – primarily in the western deepwater Gulf of Mexico – that are expected to provide attractive returns on investment.

Updated Cap-Ex Guidance

	NEW	PREVIOUS
2006	$2.175 billion - $2.375 billion	$2.2 billion - $2.4 billion
2007	$2 billion - $2.2 billion	$1.775 billion -$1.975 billion
2008	$1.8 billion - $2.05 billion	$1.575 billion-$1.825 billion

CEO Perspective

"This is the second time we've raised our earnings guidance this year," said Steve Malcolm, Williams' chairman, president and chief executive officer. "And we like the momentum we have going into 2007 and beyond."

"Our outlook is based on the fact that our natural gas production continues to rapidly climb, our older below-market hedges for that production are beginning to roll off, we see sustained strength in NGL sales margins, and our Midstream business has sizeable opportunities on the horizon.

"As we've shown, we're poised to capture value creation with diligence, determination and fiscal discipline. Our businesses offer unique capabilities that our customers value. Our assets are strategically located in areas where we can capture meaningful growth. The scale of our operations gives us competitive advantages. And our liquidity and cash flow remain very robust.

"Overall, our portfolio of businesses is performing extremely well. Our business diversity is designed to help us do well in different price environments. We have a great deal of balance that is evidenced in our revenue streams.

"This year is a perfect example. Our Midstream business has provided a natural hedge to the price exposure we have in Exploration & Production. So while natural gas prices have been lower, the NGL margins in Midstream have been higher – significantly higher."

Business Segment Performance: Substantial Increase in 3Q Segment Profit

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.

Recurring Segment Profit Adjusted for Mark-to-Market Effect *Amounts are reported in millions*	3Q 2006	3Q 2005	YTD 2006	YTD 2005
Segment profit	$395.8	$204.5	$1,101.0	$ 970.6
Nonrecurring adjustments	$ 1.1	$ (35.5)	$ 60.8	$ (0.3)
Recurring segment profit	$396.9	$169.0	$1,161.8	$ 970.3
Reverse forward unrealized mark-to-market (gains) losses	$ 15.5	$141.1	$ 11.1	$ (102.1)
Add realized mark-to-market gains previously recognized	$ 80.0	$ 71.9	$ 256.9	$ 262.2
Recurring segment profit after mark-to-market adjustments	$492.4	$382.0	$1,429.8	$1,130.4

Williams' businesses reported consolidated segment profit of $395.8 million in the third-quarter this year, 94 percent higher than $204.5 million a year ago.

These significantly higher results in third-quarter 2006 are primarily attributable to higher margins for NGL sales, significantly lower levels of forward unrealized mark-to-market losses and increased natural gas production. These benefits were partially offset by higher operating and maintenance costs.

For the first three quarters of 2006, Williams' businesses reported consolidated segment profit of $1.1 billion, an increase of 13 percent compared with $970.6 million for the same period in 2005.

Results for the first nine months of 2005 benefited from $102.1 million of forward unrealized mark-to-market gains in Power, compared with a forward unrealized loss of $11.1 million for the same period in 2006. The 2006 period also includes approximately $70 million in litigation accruals associated with the Gulf Liquids verdict earlier this year.

On a basis adjusted to remove the effect of nonrecurring items and mark-to-market accounting, Williams had recurring consolidated segment profit of $492.4 million in third-quarter 2006, compared with $382.0 million a year ago – an increase of 29 percent. On the same basis, Williams had recurring consolidated segment profit of approximately $1.4 billion in the first three quarters of 2006, compared with approximately $1.1 billion for the same period in 2005 – an increase of 26 percent.

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

For the first three quarters of 2006, net cash provided by operating activities was approximately $1.3 billion, compared with approximately $1.1 billion for the same period in 2005. Net cash generated this year is primarily being reinvested in capital expenditures.

Williams invested approximately $1.8 billion in capital expenditures in the first nine months this year, essentially doubling investments of approximately $886 million in the same period a year ago.

Exploration & Production: Volumes Up 22% From Year Ago

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 third-quarter 2006 segment profit of $144.5 million, compared with segment profit of $158.8 million a year ago. The third quarter of 2005 included the benefit of a $21.7 million gain on the sale of certain properties in the Powder River Basin.

Average daily production from domestic and international interests in third-quarter 2006 totaled 831 MMcfe, an increase of 22 percent compared with volumes of 682 MMcfe in third-quarter 2005.

Third-quarter 2006 average daily production in the Piceance Basin was 430 MMcfe – up 31 percent compared with 329 MMcfe in third-quarter 2005.

Production in the Powder River Basin also increased – up 23 percent to 147 MMcfe, compared with 120 MMcfe a year ago. Increased production in the Powder River primarily is coming from volumes in the Big George area of the basin.

The benefit of higher production volumes in the third quarter of 2006 was partially offset by 10 percent lower domestic net realized average prices; increased lease operating expenses; higher depreciation, depletion and amortization; and higher general and administrative expenses due to increased business activities and generally higher industry costs. However, third-quarter 2006 included a $5 million unrealized gain from hedge ineffectiveness and certain basis swaps not designated as hedges, compared with a $16 million unrealized loss for third-quarter 2005.

For the first nine months of 2006, Exploration & Production reported segment profit of $411.9 million, an increase of 8 percent compared with $380.8 million for the first three quarters of 2005.

The improvement in the first three quarters of 2006 primarily reflects increased production volumes. The first nine months of 2006 also include a $21 million unrealized gain from hedge ineffectiveness and certain basis swaps not designated as hedges, compared with a $16 million unrealized loss for the same period in 2005.

Year-to-date increases in 2006 were partially offset by the same expense items previously noted for the third quarter, as well as the absence of gains totaling $29.6 million on the sale of certain assets in 2005.

Williams now has 24 rigs operating in the Piceance Basin of western Colorado – 9 more than it had at this time a year ago. The rig count includes eight new-generation drilling rigs that are purpose-built for conditions in the tight-sands development. Two more of the new rigs are scheduled for delivery later this year.

Williams is on pace to invest $1.15 billion to $1.25 billion in Exploration & Production in 2006. These investments primarily focus on increasing the pace of developing the company's natural gas reserves.

Williams has narrowed the range of segment profit it expects from Exploration & Production in 2006 based on lower domestic net realized prices and higher lease operating expenses in the third quarter. The company now expects $550 million to $600 million in segment profit for this business. The company's prior guidance was $550 million to $650 million.

Midstream Gas & Liquids: 3Q Segment Profit Rises 75 Percent

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

This business reported segment profit of $212.2 million in the third quarter, up 75 percent compared with $121.1 million a year ago.

The significant increase in Midstream's results is primarily from higher margins realized from the company's NGL sales. Per-unit margins in third-quarter 2006 were approximately 112 percent higher than margins in the same period a year ago. Williams markets natural gas liquids via equity volumes the company retains as payment-in-kind under certain processing contracts.

In addition, Williams experienced strong growth in production handling volumes and revenues in the deepwater Gulf of Mexico, and higher fee-based gathering and processing revenues. The 2006 quarter also benefited from $7.9 million in gains on asset sales. These benefits were partially offset by higher operating expenses, a $10.6 million adjustment to increase accrued accounts payable and a $5.2 million loss associated with an asset abandonment.

In third-quarter 2006, Midstream sold 334.0 million gallons of NGL equity volumes – 21 percent higher than equity sales of 276.4 million gallons in third-quarter 2005.

For the first nine months of 2006, Midstream reported segment profit of $494.4 million, 38 percent higher than $358.8 million for the first three quarters of 2005.

The improvement in 2006 primarily reflects a $164.2 million increase in NGL 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 by higher operating expenses and approximately $70 million in litigation accruals associated with the Gulf Liquids matter.

Year-to-date through Sept. 30, the sale of Williams' NGL equity volumes has generated margins of $323.4 million, 103 percent higher than margins of $159.2 million for the same period in 2005. Higher margins during the first three quarters of 2006 are primarily the result of the difference between higher liquids prices – which typically track closely with crude oil prices – and lower natural gas prices.

The Cameron Meadows natural gas processing plant in Louisiana's Cameron Parish is returning to its full design capacity after being damaged by Hurricane Rita in September 2005. The plant is expected to be available to process up to 500 MMcf/d of natural gas in early November as crews finalize the startup procedures on the plant's second processing unit. Cameron Meadows had been operating at about half of its design capacity since February.

Williams is raising its guidance again for segment profit it expects from Midstream. The company now expects $675 million to $750 million in segment profit for this business in 2006 based on its performance in the first three quarters and Williams' outlook for strong NGL prices. The company's prior guidance in August was $550 million to $675 million in segment profit for Midstream.

Gas Pipeline: Capacity Replacement Project Nearing Completion

Gas Pipeline primarily delivers natural gas to markets along the Eastern Seaboard, in the Northwest, and in Florida. This business reported third-quarter 2006 segment profit of $109.0 million, down 32 percent compared with $161.1 million a year ago.

Results for the third quarter of 2006 were reduced by approximately $22 million in higher selling, general and administrative costs primarily due to higher personnel costs, property insurance costs and information systems support costs. In addition, the results reflect approximately $8 million in lower equity earnings and higher operating and maintenance costs related to pipeline assessment and repair costs.

The third-quarter of 2005 benefited from a $14 million favorable adjustment from the resolution of litigation associated with Gas Pipeline's fuel tracker filings.

New rates for both of Williams' wholly-owned interstate transmission systems – Transco and Northwest Pipeline – will be effective, subject to refund, in first-quarter 2007. Northwest Pipeline filed its rate case with the Federal Energy Regulatory Commission on June 30. Transco filed its rate case Aug. 31. The filings reflect, among other things, current levels of operating costs and rate base.

For the first nine months of 2006, Gas Pipeline reported segment profit of $366.4 million, down 26 percent compared with $493.0 million for the same period in 2005.

The reduction for the first three quarters of 2006 is attributable to higher operating and maintenance costs; higher selling, general and administrative costs, including the absence of a $34.8 million benefit in prior-period adjustments recorded in 2005; and the absence of the $14 million benefit of the 2005 fuel tracker settlement. The increased costs are primarily due to the same factors previously mentioned for the third quarter.

In July, Transco filed an application with the Federal Energy Regulatory Commission to provide additional capacity to the greater Washington D.C. and Baltimore metropolitan areas. The proposal, known as the Potomac Expansion, is designed to increase firm transportation capacity by 165,000 dekatherms per day beginning in November 2007.

In August, the commission also issued a certificate enabling Northwest Pipeline to proceed with a 37-mile expansion in Colorado known as the Parachute Lateral project. The 450,000-dekatherm expansion is scheduled to be completed by January 2007.

Northwest Pipeline expects to have its Capacity Replacement project between Sumas, Wash., and Washougal, Wash., in service by December. The company abandoned 268-miles of 26-inch diameter pipeline and replaced its 360,000 dekatherms of capacity with 80-miles of 36-inch diameter pipeline in four sections along the same corridor. Startup operations on the new pipeline sections began the week of Oct. 23.

Williams has narrowed the range of segment profit it expects from Gas Pipeline. The company now expects $475 million to $500 million in segment profit for this business in 2006. Williams previously expected $475 million to $520 million in segment profit for Gas Pipeline.

Power: Solid Performance as Expected

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

Power Recurring Segment Profit (Loss) Adjusted for Mark-to-Market Effect	**3Q**		**YTD**	
Amounts are reported in millions	2006	2005	2006	2005
Segment loss	$(69.7)	$(226.4)	$(171.8)	$(187.3)
Nonrecurring adjustments	$ (9.2)	$ 0.4	$ (9.2)	$ 24.9
Recurring segment loss	$(78.9)	$(226.0)	$(181.0)	$(162.4)
Mark-to-market adjustments — net	$ 95.5	$ 213.0	$ 268.0	$ 160.1
Recurring segment profit (loss) after MTM adjustments	$ 16.6	$ (13.0)	$ 87.0	$ (2.3)

Power reported a third-quarter 2006 segment loss of $69.7 million, compared with a segment loss of $226.4 million for third-quarter 2005. Results include the effect of forward noncash unrealized mark-to-market gains and losses.

The improved results in third-quarter 2006 are primarily the result of lower noncash unrealized mark-to-market losses, higher accrual portfolio earnings and the benefit of a $12.7 million reduction in contingent obligations associated with a former business. The improvement was partially offset by a $3.5 million litigation accrual.

On a basis adjusted for the effect of mark-to-market accounting, Power reported recurring segment profit of $16.6 million in third-quarter 2006, compared with a recurring segment loss of $13.0 million in the 2005 period.

The improvement in third-quarter 2006 recurring segment profit adjusted to remove the effect of mark-to-accounting reflects the benefit of having additional megawatts economically hedged on Power's tolling positions. Third-quarter 2006 adjusted results include approximately $13 million of losses related to the write-down of natural gas storage inventory due to falling prices and $7 million of certain related realized hedge losses.

These losses – on a basis adjusted for mark-to-market accounting – are timing-related only. The company expects to recover these losses since the inventory is hedged at fixed prices.

For the first nine months of 2006, Power reported a segment loss of $171.8 million, compared with a segment loss of $187.3 million for the first three quarters of 2005. The improved results in 2006 are primarily the result of higher accrual portfolio earnings and a $24.8 million gain on the sale of certain third party receivables in first-quarter 2006, offset by lower noncash unrealized mark-to-market earnings.

The 2006 period includes forward unrealized mark-to-market losses of $11.1 million, compared with forward unrealized mark-to-market gains of $102.1 million in the first nine months of 2005. The year-over-year variance resulted primarily from commodity price changes on fewer nondesignated contracts subject to mark-to-market accounting.

For the first nine months of 2006, Power reported a recurring segment profit on a basis to remove the effect of mark-to-market accounting of $87.0 million, significantly improved compared with a loss $2.3 million for the first three quarters of 2005.

The year-to-date improvement primarily reflects the benefits of having additional megawatts economically hedged on Power's tolling positions, the liquidation of certain non-core basis positions in the gas portfolio and lower expenses from the positive effect of a gain on the sale of certain third-party receivables in the first quarter.

The 2006 adjusted results also include $20 million of storage-related losses for the write-down of natural gas inventory due to falling prices and $30 million of certain related realized hedge losses. These losses – on a basis adjusted for mark-to-market accounting – are timing-related only. The company expects to recover these losses since the inventory is hedged at fixed prices.

For 2006, Williams now expects a segment loss of $190 million to $240 million from Power, which includes year-to-date unrealized mark-to-market losses on derivative contracts but assumes no future change in fair value on these contracts. Williams previously expected a segment loss of $150 million to $200 million from Power.

Williams continues to expect Power to generate 2006 recurring segment profit of $75 million to $125 million after removing the effect of mark-to-market accounting.

Today's Analyst Call

Williams' management will discuss the company's third-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) 500-0311. International callers should dial (719) 457-2698. Callers should dial in at least 10 minutes prior to the start of the discussion. Replays of the third-quarter webcast will be available for two weeks at www.williams.com.

Form 10-Q

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

About Williams (NYSE:WMB)

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

Contact: Julie Gentz
Williams (media relations)
(918) 573-3053

Travis Campbell
Williams (investor relations)
(918) 573-2944

Richard George
Williams (investor relations)
(918) 573-3679

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

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

September 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*	*3rd 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)	$ 110.1	$ 177.3
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)	$ 0.19	$ 0.29
Nonrecurring items:									
Exploration & Production									
Gains on sales 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									
Gains on sales of MGL properties	—	—	—	—	—	—	—	(7.9)	(7.9)
Adjustment of accounts payable accrual	—	—	—	—	—	—	—	10.6	10.6
Losses on asset retirements and abandonments	—	—	—	—	—	—	—	5.2	5.2
Accrual for Gulf Liquids litigation contingency	—	—	—	—	—	—	68.0	2.4	70.4
Settlement of an international contract dispute	—	—	—	—	—	(6.3)	—	—	(6.3)
Total Midstream Gas & Liquids nonrecurring items	—	—	—	—	—	(6.3)	68.0	10.3	72.0
Power									
Reduction of contingent obligations associated with our former distributive power generation business	—	—	—	—	—	—	—	(12.7)	(12.7)
Accrual for a regulatory settlement (1)	4.6	—	—	—	4.6	—	—	—	—
Accrual for litigation contingencies (1)	—	13.1	0.4	68.7	82.2	—	—	3.5	3.5
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	—	—	(9.2)	(9.2)
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	1.1	60.8
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	3.4	165.3
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	0.6	20.6
	2.7	(8.6)	18.8	9.4	22.3	16.5	185.1	4.0	205.6
Total nonrecurring items	(6.6)	35.9	(16.7)	167.5	180.1	8.2	253.1	5.1	266.4
Tax effect for above items (1)	(2.8)	10.7	(6.4)	48.0	49.5	3.4	76.6	1.8	81.8
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	$ 113.4	$ 361.9
Recurring diluted earnings (loss) per common share	$ 0.33	$ 0.11	($0.01)	$ 0.28	$ 0.72	$ 0.23	$ 0.19	$ 0.19	$ 0.60
Weighted-average shares — diluted (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	609,062	608,045

(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 3rd 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	$ 3,300.0	$ 9,042.6
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	2,822.4	7,684.9
Selling, general and administrative expenses	73.5	62.7	90.6	98.6	325.4	71.0	109.3	128.0	308.3
Other (income) expense — net	(1.8)	21.9	(21.4)	62.5	61.2	(22.3)	61.7	(15.8)	23.6
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	2,934.6	8,016.8
Equity earnings	17.7	9.8	17.6	20.5	65.6	22.2	23.1	29.9	75.2
Income (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**	**395.8**	**1,101.0**
Reclass equity earnings	(17.7)	(9.8)	(17.6)	(20.5)	(65.6)	(22.2)	(23.1)	(29.9)	(75.2)
Reclass income (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)	(35.0)	(99.3)
Securities litigation settlement and related fees	—	—	—	—	—	(1.2)	(160.7)	(3.4)	(165.3)
Operating income	464.0	259.5	144.1	303.5	1,171.1	358.3	75.9	327.0	761.2
Interest accrued	(164.7)	(164.6)	(166.0)	(176.4)	(671.7)	(162.8)	(181.5)	(162.7)	(507.0)
Interest capitalized	1.1	1.4	1.8	2.9	7.2	3.0	4.0	4.8	11.8
Investing income (loss)	31.0	(17.2)	31.1	(21.2)	23.7	46.9	43.3	50.7	140.9
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)	(12.1)	(27.5)
Other income (expense) — net	5.5	8.1	(1.1)	14.6	27.1	8.1	8.0	2.8	18.9
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)	210.5	366.9
Provision (benefit) for income taxes	129.5	41.7	(2.6)	45.3	213.9	88.3	0.9	100.4	189.6
Income (loss) from continuing operations	**202.2**	**40.7**	**5.7**	**68.8**	**317.4**	**131.1**	**(63.9)**	**110.1**	**177.3**
Income (loss) from discontinued operations	(1.1)	0.6	(1.3)	(0.3)	(2.1)	0.8	(12.1)	(3.9)	(15.2)
Income (loss) before cumulative effect of change in accounting principle	201.1	41.3	4.4	68.5	315.3	131.9	(76.0)	106.2	162.1
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)**	**$ 106.2**	**$ 162.1**
Diluted earnings per common share:									
Income (loss) from continuing operations	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.11)**	**$ 0.19**	**$ 0.29**
Loss from discontinued operations	—	—	—	—	—	—	**(0.02)**	(0.01)	**(0.02)**
Net income (loss)	**$ 0.34**	**$ 0.07**	**$ 0.01**	**$ 0.11**	**$ 0.53**	**$ 0.22**	**$ (0.13)**	**$ 0.18**	**$ 0.27**
Weighted-average number of shares used in computation (thousands)	599,422	578,902	580,735	609,106	605,847	607,073	595,561	609,062	608,045
Common shares outstanding at end of period (thousands)	570,501	571,502	572,922	573,592	573,592	595,007	595,562	596,130	596,130
Market price per common share (end of period)	$ 18.81	$ 19.00	$ 25.05	$ 23.17	$ 23.17	$ 21.39	$ 23.36	$ 23.87	$ 23.87
Common dividends per share	$ 0.05	$ 0.05	$ 0.075	$ 0.075	$ 0.25	$ 0.075	$ 0.09	$ 0.09	$ 0.255

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)

	2005					2006			
(Dollars in millions)	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	*1st Qtr*	*2nd Qtr*	*3rd Qtr*	*Year*
Segment profit (loss):									
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 144.5	$ 411.9
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	109.0	366.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	212.2	494.4
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(69.7)	(171.8)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	(0.2)	0.1
Total segment profit	**$ 509.7**	**$ 256.4**	**$ 204.5**	**$ 311.9**	**$1,282.5**	**$ 412.3**	**$ 292.9**	**$ 395.8**	**$1,101.0**
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	10.3	72.0
Power	11.4	13.1	0.4	91.7	116.6	—	—	(9.2)	(9.2)
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**	**$ 1.1**	**$ 60.8**
Recurring segment profit (loss):									
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	144.5	411.9
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	109.0	364.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	222.5	566.4
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(78.9)	(181.0)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	(0.2)	0.1
Total recurring segment profit	**$ 500.4**	**$ 300.9**	**$ 169.0**	**$ 470.0**	**$1,440.3**	**$ 404.0**	**$ 360.9**	**$ 396.9**	**$1,161.8**

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

Exploration & Production
(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 3rd Qtr	2006 Year
Revenues:									
Production	$210.2	$234.8	$283.0	$344.4	$1,072.4	$286.8	$287.9	$316.1	$ 890.8
Gas management	28.2	32.6	32.1	52.0	144.9	41.2	28.3	25.3	94.8
Net nonqualified hedge derivative income (loss)	(0.1)	0.6	(15.9)	9.8	(5.6)	12.8	(1.6)	1.8	13.0
International	10.8	11.6	16.3	14.7	53.4	16.0	15.1	16.8	47.9
Other	(0.1)	1.9	2.9	(0.7)	4.0	(0.8)	12.6	11.1	22.9
Total revenues	249.0	281.5	318.4	420.2	1,269.1	356.0	342.3	371.1	1,069.4
Segment costs and expenses:									
Depreciation, depletion and amortization (including International)	58.5	59.5	66.4	69.6	254.0	73.1	84.5	95.3	252.9
Lease and other operating expenses *	23.8	23.9	28.5	29.0	105.2	30.1	43.8	39.0	112.9
Operating taxes	21.1	23.9	26.7	29.4	101.1	31.8	28.1	31.1	91.0
Exploration expenses *	0.9	1.1	1.5	4.1	7.6	4.4	2.4	2.6	9.4
Gathering expense	5.6	6.0	5.0	8.1	24.7	6.4	7.5	7.6	21.5
Selling, general and administrative expenses (including International)	17.0	17.7	20.3	24.6	79.6	21.5	28.2	28.2	77.9
Gas management expenses	28.2	32.6	32.1	52.0	144.9	41.2	28.3	25.3	94.8
International (excluding DD&A and SG&A)	3.3	3.3	4.7	3.6	14.9	5.5	4.9	5.0	15.4
Other (income) expense — net	(9.6)	(1.2)	(19.8)	(0.7)	(31.3)	(0.6)	0.7	(1.9)	(1.8)
Total segment costs and expenses	148.8	166.8	165.4	219.7	700.7	213.4	228.4	232.2	674.0
Equity earnings — International	3.5	3.6	5.8	5.9	18.8	5.0	5.9	5.6	16.5
Reported segment profit	**103.7**	**118.3**	**158.8**	**206.4**	**587.2**	**147.6**	**119.8**	**144.5**	**411.9**
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**	**$144.5**	**$ 411.9**

* Amounts have been reclassified to the current classifications.

Operating statistics

	2005 1st Qtr	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 Year
Domestic:									
Total domestic net volumes (Bcfe)	51.1	55.0	57.9	59.5	223.5	59.5	67.1	71.8	198.4
Net domestic volumes per day (MMcfe/d)	568	604	629	646	612	661	738	780	727
Net domestic realized price ($/Mcfe) (1)	$4.001	$4.164	$4.801	$5.655	$ 4.688	$4.712	$4.177	$4.300	$ 4.382
Production taxes per Mcfe	$0.413	$0.435	$0.462	$0.493	$ 0.452	$0.534	$0.420	$0.433	$ 0.459
Lease and other operating expense per Mcfe	$0.466	$0.436	$0.492	$0.486	$ 0.471	$0.505	$0.653	$0.544	$ 0.569

(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	2005 2nd Qtr	2005 3rd Qtr	2005 4th Qtr	2005 Year	2006 1st Qtr	2006 2nd Qtr	2006 3rd Qtr	2006 Year
International:									
Total volumes including Equity Investee (Bcfe)	5.3	5.5	6.1	6.0	22.9	6.0	5.6	6.0	17.6
Volumes per day (MMcfe/d)	59	61	67	65	63	67	61	65	64
Volumes net to Williams (after minority interest) (Bcfe)	4.1	4.3	4.8	4.8	18.0	4.7	4.4	4.7	13.8
Volumes net to Williams per day (MMcfe/d)	46	48	53	51	49	53	48	51	51
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	76.5	212.2
Volumes net to Williams per day (MMcfe/d)	614	652	682	697	662	714	786	831	777

Gas Pipeline
(UNAUDITED)

(Dollars in millions)	2005 *1st Qtr*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	2006 *1st Qtr*	*2nd Qtr*	*3rd Qtr*	*Year*
Revenues:									
Northwest Pipeline	$ 80.3	$ 78.9	$ 79.6	$ 82.7	$ 321.5	$ 79.6	$ 80.0	$ 81.0	$ 240.6
Transcontinental Gas Pipe Line	254.9	278.1	266.0	292.0	1,091.0	254.3	257.2	253.0	764.5
Other	0.1	—	0.2	—	0.3	0.1	0.1	0.2	0.4
Total revenues	335.3	357.0	345.8	374.7	1,412.8	334.0	337.3	334.2	1,005.5
Segment costs and expenses:									
Costs and operating expenses	160.4	193.3	177.6	250.7	782.0	177.2	192.8	192.2	562.2
Selling, general and administrative expenses	18.6	6.8	23.6	35.1	84.1	31.0	35.4	45.1	111.5
Other (income) expense — net	0.3	0.3	0.5	3.4	4.5	(1.4)	(3.4)	(2.4)	(7.2)
Total segment costs and expenses	179.3	200.4	201.7	289.2	870.6	206.8	224.8	234.9	666.5
Equity earnings	11.4	7.9	17.0	7.3	43.6	7.5	10.7	9.2	27.4
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	31.8	97.9
Transcontinental Gas Pipe Line	117.9	121.8	107.0	50.1	396.8	95.8	81.3	69.5	246.6
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	7.7	21.9
Total reported segment profit	**167.4**	**164.5**	**161.1**	**92.8**	**585.8**	**134.7**	**122.7**	**109.0**	**366.4**
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	31.8	97.9
Transcontinental Gas Pipe Line	104.8	100.1	92.8	87.4	385.1	93.8	81.3	69.5	244.6
Other	9.8	6.2	15.0	5.5	36.5	5.6	8.6	7.7	21.9
Total recurring segment profit, pre-tax	**$ 154.3**	**$ 142.8**	**$ 146.9**	**$ 130.1**	**$ 574.1**	**$ 132.7**	**$ 122.7**	**$ 109.0**	**$ 364.4**
Operating statistics									
Northwest Pipeline									
Throughput (TBtu)	181.2	146.2	152.9	192.6	672.9	179.7	142.7	156.6	479.0
Average daily transportation volumes (TBtu)	2.0	1.6	1.7	2.1	1.9	2.0	1.6	1.7	1.8
Average daily firm reserved capacity (TBtu)	2.5	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	471.3	1,401.1
Average daily transportation volumes (TBtu)	6.0	4.7	4.9	5.1	5.2	5.6	4.6	5.1	5.1
Average daily firm reserved capacity (TBtu)	6.9	6.5	6.4	6.8	6.7	7.0	6.4	6.4	6.6

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 *3rd Qtr*	2006 *Year*
Revenues:									
Gathering	$ 70.6	$ 74.2	$ 74.0	$ 75.8	$ 294.6	$ 76.8	$ 79.0	$ 79.2	$ 235.0
Processing	23.5	24.3	25.5	22.9	96.2	24.9	27.4	27.6	79.9
Venezuela fee revenue	36.5	37.8	40.4	38.8	153.5	38.9	38.0	40.6	117.5
NGL sales from gas processing	285.1	247.0	244.2	259.0	1,035.3	263.7	292.6	296.6	852.9
Production handling and transportation	18.6	20.4	14.7	20.6	74.3	37.2	33.2	33.0	103.4
Olefins sales (Incl Gulf and Canada)	146.6	114.2	121.4	185.3	567.5	148.9	131.4	175.9	456.2
Trading/marketing sales	588.0	574.4	522.0	578.1	2,262.5	709.0	806.1	863.9	2,379.0
Other revenues	23.7	33.2	31.7	39.1	127.7	34.4	30.7	28.8	93.9
	1,192.6	1,125.5	1,073.9	1,219.6	4,611.6	1,333.8	1,438.4	1,545.6	4,317.8
Intrasegment eliminations	(385.6)	(345.4)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(428.6)	(1,177.9)
Total revenues	807.0	780.1	754.7	890.9	3,232.7	979.4	1,043.5	1,117.0	3,139.9
Segment costs and expenses:									
NGL cost of goods sold	225.1	202.4	189.6	218.3	835.4	199.9	172.7	156.9	529.5
Olefins cost of goods sold	118.7	104.0	102.2	163.5	488.4	132.8	108.1	141.2	382.1
Trading/marketing cost of goods sold	584.0	574.7	510.1	575.8	2,244.6	716.7	799.1	863.4	2,379.2
Venezuela operating costs	16.1	16.0	17.4	17.6	67.1	16.8	18.1	17.1	52.0
Operating costs	101.6	101.5	112.8	113.9	429.8	120.6	120.7	134.2	375.5
Other									
Selling, general and administrative expenses	22.9	21.0	23.1	29.3	96.3	23.3	25.2	31.1	79.6
Other (income) expense — net	2.6	1.7	0.8	(1.7)	3.4	(17.9)	70.0	(3.2)	48.9
Intrasegment eliminations	(385.5)	(345.5)	(319.2)	(328.7)	(1,378.9)	(354.4)	(394.9)	(428.6)	(1,177.9)
Total segment costs and expenses	685.5	675.8	636.8	788.0	2,786.1	837.8	919.0	912.1	2,668.9
Equity earnings	7.1	4.1	3.2	9.2	23.6	9.9	6.2	7.3	23.4
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**	**212.2**	**494.4**
Nonrecurring adjustments	—	—	—	—	—	(6.3)	68.0	10.3	72.0
Recurring segment profit, pre-tax	**$ 128.6**	**$ 109.1**	**$ 121.1**	**$ 112.4**	**$ 471.2**	**$ 145.2**	**$ 198.7**	**$ 222.5**	**$ 566.4**
Operating statistics									
Gathering volumes (TBtu)	315.5	323.6	310.3	303.9	1,253.3	296.9	300.1	292.5	889.5
Gathering margins ($/MMBtu)	$ 0.2237	$ 0.2292	$ 0.2386	$ 0.2496	$ 0.2351	$ 0.2590	$ 0.2634	$ 0.2708	$ 0.2642
Processing volumes (TBtu)	181.0	184.5	190.3	165.6	721.4	191.8	204.8	210.0	606.6
Processing rate ($/MMBtu)	$ 0.1299	$ 0.1316	$ 0.1342	$ 0.1381	$ 0.1334	$ 0.1298	$ 0.1340	$ 0.1314	$ 0.1317
NGL equity sales (million gallons)	398.7	338.3	276.4	255.8	1,269.2	333.7	361.3	334.0	1,029.0
NGL margin ($/gallon)	$ 0.1503	$ 0.1318	$ 0.1976	$ 0.1565	$ 0.1569	$ 0.1900	$ 0.3319	$ 0.4183	$ 0.3143
Olefins sales (Ethylene & Propylene) (million lbs)	266.5	265.6	258.1	275.9	1,066.1	259.2	196.8	268.1	724.1

Power
(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 3rd Qtr	2006 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	$2,104.1	$5,764.0
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	2,104.1	$5,764.3
Segment costs and expenses:									
Costs and operating expenses	1,930.3	2,041.1	2,450.9	2,750.2	9,172.5	2,082.1	1,671.4	2,167.6	5,921.1
Selling, general and administrative expenses	16.0	16.9	21.1	10.5	64.5	(4.5)	18.9	22.2	36.6
Other (income) expense — net	5.6	17.3	(1.7)	95.5	116.7	(2.1)	(3.4)	(8.4)	(13.9)
Total segment costs and expenses	1,951.9	2,075.3	2,470.3	2,856.2	9,353.7	2,075.5	1,686.9	2,181.4	5,943.8
Equity Earnings	1.1	0.9	1.0	0.1	3.1	(0.2)	0.3	7.6	7.7
Reported segment profit (loss)	**114.1**	**(75.0)**	**(226.4)**	**(69.4)**	**(256.7)**	**(22.5)**	**(79.6)**	**(69.7)**	**(171.8)**
Nonrecurring adjustments	11.4	13.1	0.4	91.7	116.6	—	—	(9.2)	(9.2)
Recurring segment profit (loss), pre-tax	**$ 125.5**	**$ (61.9)**	**$ (226.0)**	**$ 22.3**	**$ (140.1)**	**$ (22.5)**	**$ (79.6)**	**$ (78.9)**	**$ (181.0)**
Operating statistics									
Volumes									
Natural gas (Bcfd)									
Sales to third parties	1.7	1.8	1.7	1.7	1.7	1.7	1.5	1.7	1.6
Sales to other segments	0.6	0.4	0.3	0.3	0.4	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	0.4	0.2
Total managed	2.5	2.4	2.3	2.1	2.3	2.2	2.1	2.5	2.2
Crude & refined products (MBPD)	—	—	—	—	—	—	—	—	—
Power (GWh)	14,832	15,906	21,690	14,559	66,987	11,505	12,949	17,430	41,884

Additional statistics

Value at risk

	Quarter ended 9/30/2006 (in Millions)
One day VaR - 95% confidence level	
Trading	$ 1.8MM
Non-Trading	$ 16.3MM
Aggregate Earnings VaR	$ 5.2MM

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

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

Net Credit Exposure

(in Millions)	Investment Grade	Total
Gas and electric utilities	$ 177.7	$ 177.9
Energy marketers and traders	279.1	589.1
Financial institutions	198.9	198.9
Other	23.8	23.8
	$ 679.5	$ 989.7
Credit Reserves		(25.1)
Net Credit Exposure from Derivative Contracts		$ 964.6

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	$ 25.0
13-36 months	0.7
37-60 months	(0.7)
61-120 months	(0.4)
121+ months	0.1
Total Fair Value	24.7
Non-Trading MTM Derivatives and SFAS 133 Hedges	378.6
Non-Power Business Unit Hedges	23.7
Total Net Derivative Assets and Liabilities	$ 427.0

Power Portfolio (Megawatts)	**Quarter Ended 9/30/06**	**9/30/05**
Owned	207	207
Contracted	8,114	9,012
Total	8,321	9,219

Credit Support (in Millions)

As of September 30, 2006	
Prepays	$5
Margins	$0
Adequate Assurance	$9

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 3rd Qtr	2006 Year
Capital expenditures:									
Exploration & Production	$ 158.6	$ 182.8	$ 211.1	$ 230.8	$ 783.3	$ 310.3	$ 283.9	$ 384.9	$ 979.1
Gas Pipeline:									
Northwest Pipeline	12.0	29.6	43.2	52.2	137.0	40.3	96.0	177.4	313.7
Transcontinental Gas Pipe Line	35.7	55.0	80.7	83.1	254.5	46.4	106.7	109.4	262.5
Other	—	—	—	2.2	2.2	—	—	—	—
Total	47.7	84.6	123.9	137.5	393.7	86.7	202.7	286.8	576.2
Midstream Gas & Liquids	16.3	25.5	32.7	40.7	115.2	70.7	39.3	83.5	193.5
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	(0.1)	1.1
Other	(0.7)*	0.1	1.2	4.0	4.6	—	7.8	1.2	9.0
Total	**$ 222.9**	**$ 293.7**	**$ 369.3**	**$ 413.1**	**$1,299.0**	**$ 468.3**	**$ 534.3**	**$ 756.3**	**$1,758.9**
Purchase of investments:									
Exploration & Production	$ 6.3	$ —	$ 0.3	$ —	$ 6.6	$ —	$ —	$ —	$ —
Gas Pipeline	—	—	—	—	—	—	—	4.5	4.5
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	4.6	43.7
Total	**$ 26.3**	**$ 55.6**	**$ 16.3**	**$ 17.9**	**$ 116.1**	**$ 9.7**	**$ 26.8**	**$ 9.1**	**$ 45.6**
Summary:									
Exploration & Production	$ 164.9	$ 182.8	$ 211.4	$ 230.8	$ 789.9	$ 310.3	$ 283.9	$ 384.9	$ 979.1
Gas Pipeline	47.7	84.6	123.9	137.5	393.7	86.7	202.7	291.3	580.7
Midstream Gas & Liquids	16.3	60.5	44.2	40.7	161.7	67.3	40.1	83.5	190.9
Power	1.0	0.7	0.4	0.1	2.2	0.6	0.6	(0.1)	1.1
Other	19.3	20.7	5.7	21.9	67.6	13.1	33.8	5.8	52.7
Total	**$ 249.2**	**$ 349.3**	**$ 385.6**	**$ 431.0**	**$1,415.1**	**$ 478.0**	**$ 561.1**	**$ 765.4**	**$1,804.5**
Cumulative summary:									
Exploration & Production	$ 164.9	$ 347.7	$ 559.1	$ 789.9	$ 789.9	$ 310.3	$ 594.2	$ 979.1	$ 979.1
Gas Pipeline	47.7	132.3	256.2	393.7	393.7	86.7	289.4	580.7	580.7
Midstream Gas & Liquids	16.3	76.8	121.0	161.7	161.7	67.3	107.4	190.9	190.9
Power	1.0	1.7	2.1	2.2	2.2	0.6	1.2	1.1	1.1
Other	19.3	40.0	45.7	67.6	67.6	13.1	46.9	52.7	52.7
Total	**$ 249.2**	**$ 598.5**	**$ 984.1**	**$1,415.1**	**$1,415.1**	**$ 478.0**	**$1,039.1**	**$1,804.5**	**$1,804.5**

* 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*	*2nd Qtr*	*3rd Qtr*	*4th Qtr*	*Year*	2006 *1st Qtr*	*2nd Qtr*	*3rd Qtr*	*Year*
Depreciation, depletion and amortization:									
Exploration & Production	$ 58.6	$ 59.4	$ 66.4	$ 69.8	$ 254.2	$ 73.0	84.2	94.8	252.0
Gas Pipeline:									
Northwest Pipeline	17.3	17.0	17.9	18.4	70.6	18.5	18.8	19.1	56.4
Transcontinental Gas Pipe Line	49.4	48.6	49.3	49.4	196.7	50.0	51.7	51.2	152.9
Total	66.7	65.6	67.2	67.8	267.3	68.5	70.5	70.3	209.3
Midstream Gas & Liquids	46.0	46.4	49.5	50.1	192.0	49.4	49.9	49.9	149.2
Power	3.9	3.7	3.6	3.7	14.9	3.2	3.2	2.3	8.7
Other	3.0	3.0	2.9	2.7	11.6	2.9	2.7	3.1	8.7
Total	$ 178.2	$ 178.1	$ 189.6	$ 194.1	$ 740.0	$ 197.0	$ 210.5	$ 220.4	$ 627.9
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	$ 1,074.6	$ 1,074.6
Total assets	$ 26,434.1	$ 26,399.7	$ 33,655.8	$ 29,442.6	$ 29,442.6	$ 26,029.0	$ 25,617.2	$ 24,821.5	$ 24,821.5
Capital structure:									
Debt									
Current	$ 99.5	$ 98.6	$ 122.4	$ 122.6	$ 122.6	$ 175.7	$ 170.7	$ 142.3	$ 142.3
Noncurrent	$ 7,650.4	$ 7,645.7	$ 7,598.7	$ 7,590.5	$ 7,590.5	$ 7,252.8	$ 7,292.6	$ 7,275.2	$ 7,275.2
Stockholders' equity	$ 5,261.1	$ 5,353.6	$ 5,154.4	$ 5,427.5	$ 5,427.5	$ 5,925.5	$ 5,882.3	$ 6,071.2	$ 6,071.2
Debt to debt-plus-equity ratio	59.6%	59.1%	60.0%	58.7%	58.7%	55.6%	55.9%	55.0%	55.0%

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**	**$ 113**		**$ 362**	**$ 198**	**$ 66**	**$ (5)**	**$ 168**	**$ 428**
Recurring diluted earnings per common share	**$ 0.23**	**$ 0.19**	**$ 0.19**		**$ 0.60**	**$ 0.33**	**$ 0.11**	**$ (0.01)**	**$ 0.28**	**$ 0.72**
Mark-to-Market (MTM) adjustments:										
Reverse forward unrealized MTM gains/losses	(43)	38	16		11	(221)	(22)	141	(70)	(172)
Add realized gains/losses from MTM previously recognized	77	100	80		257	113	77	72	48	310
Total MTM adjustments	34	138	96		268	(108)	55	213	(22)	138
Tax effect of total MTM adjustments (at 39%)	13	53	37		103	(42)	21	83	(8)	53
After tax MTM adjustments	21	85	59		165	(66)	34	130	(14)	85
Recurring income from cont. ops available to common shareholders after MTM adjust.	**$ 157**	**$ 198**	**$ 172**		**$ 527**	**$ 132**	**$ 100**	**$ 125**	**$ 154**	**$ 513**
Recurring diluted earnings per share after MTM adj.	**$ 0.26**	**$ 0.33**	**$ 0.28**		**$ 0.87**	**$ 0.22**	**$ 0.17**	**$ 0.22**	**$ 0.26**	**$ 0.86**
weighted average shares — diluted (thousands)	607,073	595,561	609,062		608,045	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

Williams 2006
3rd Quarter Earnings

November 2, 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;

Forward Looking Statements (cont.)

- 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

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.

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

- Portfolio delivers strong quarter-over-quarter earnings
  - 38% quarter-over-quarter increase in key earnings measure*
  - 47% jump year-to-date '06 vs. '05
- Raising guidance for '06
- Production up 22% year over year
- NGL margins at historic levels
- Progress on deepwater expansion

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

Well-positioned for near- to long-term value creation

Williams

Premier assets that are opportunity rich

- **E&P – our growth:** long-lived natural gas assets and among industry's lowest development costs
- **Midstream** – significant growth potential; **strong free cash flow** from ops and drop-downs; recent record quarters with robust outlook from sustained higher NGL margins
- Gas **Pipeline – anchors credit**: expansions support stable and growing cash flows to reinvest in high-return E&P and midstream growth
- **Power**: continuing to produce **positive cash flow and reduce risk**
- **Portfolio:** provides **inherent commodity hedge**

Pursuing growth with discipline

- **EVA-based investments**
- Committed to **maintaining or improving credit** ratios/ratings
- Access to **low-cost capital** via Williams Partners L.P.

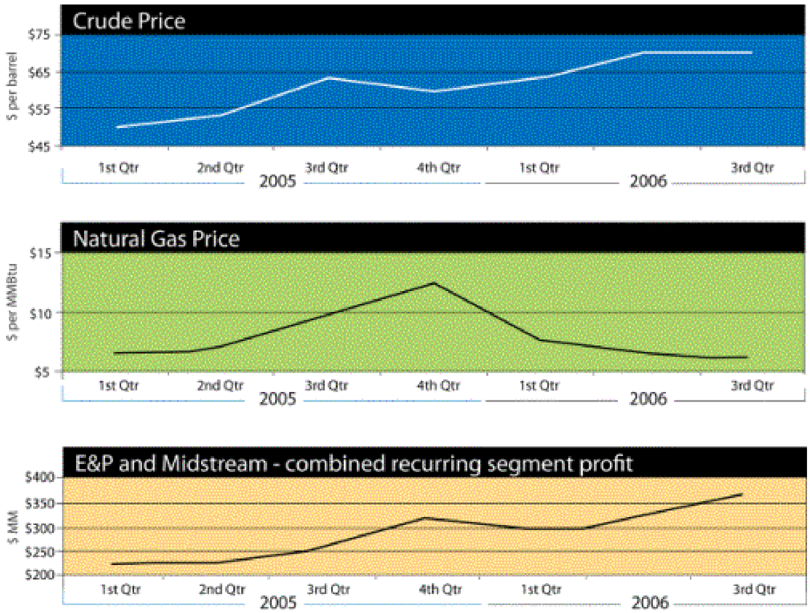
Solid record of delivering results

- 2006, 2007, 2008 **guidance increased**
- **>100% increase in segment profit** after mark-to-market effect 2003-2006
- Virtually all **secured debt eliminated**
- **Resolved** significant legacy issues
- **>100% return** to shareholders in last 8 quarters; **increased dividend 20%** in 2006 alone

Taking action to drive value creation

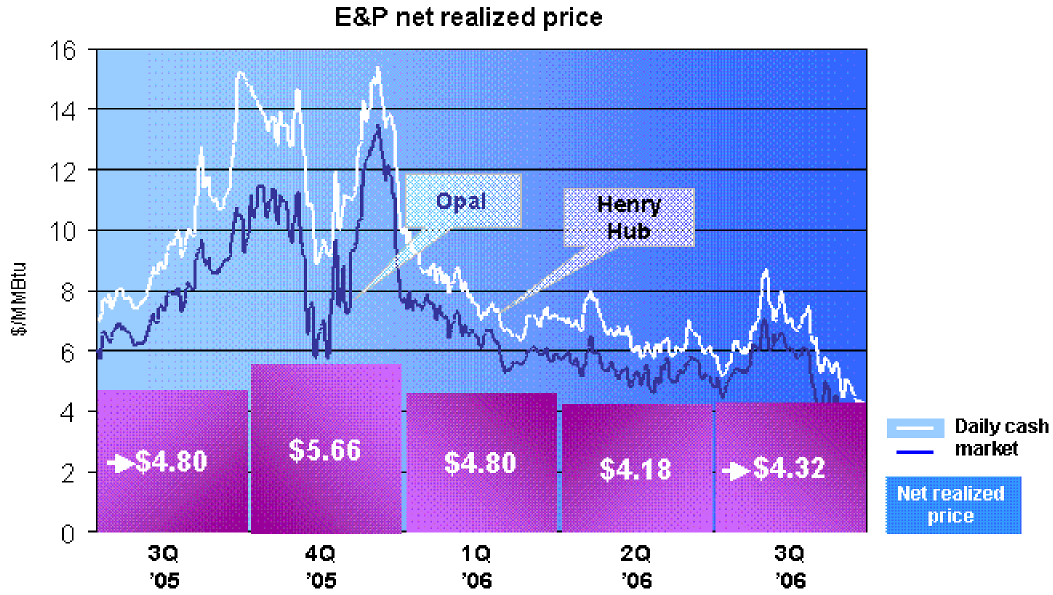
- **Accelerating** MLP **dropdowns**: $360MM so far in '06
- **Deep bench** of qualifying assets supports annual dropdowns of $1B-$2B thru 2008
- E&P **production sharply increased**, prospects good through 2008 and beyond
- **New projects and rate cases** expected to support significantly **higher pipeline profits** in 2007 and beyond

Portfolio delivers value in various price environments



Crude = West Texas Intermediate. Gas = Henry Hub. Source = Energy Information Administration

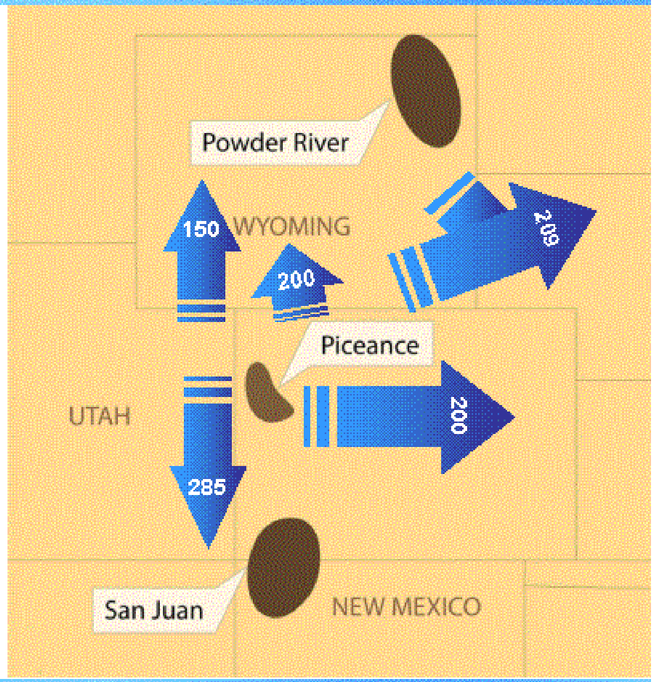
E&P net realized prices relatively unaffected by cash market drop



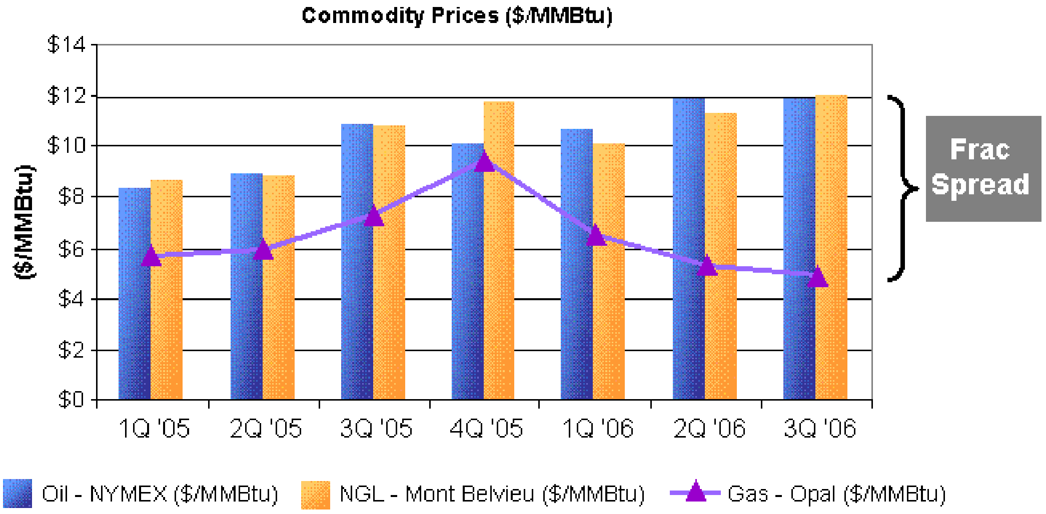
We move Piceance gas to higher-price markets for sale

- Insulated from Rockies prices for gas sales
- Our contracted pipeline capacity to moves our Rockies production to more favorable price markets

Firm Capacity Under Contract	
Wamsutter	200
East to Midcontinent	209
South to San Juan	285
Addt'l Firm Capacity Coming in '08-'09	
Opal	150
East to Appalachia (REX)	200

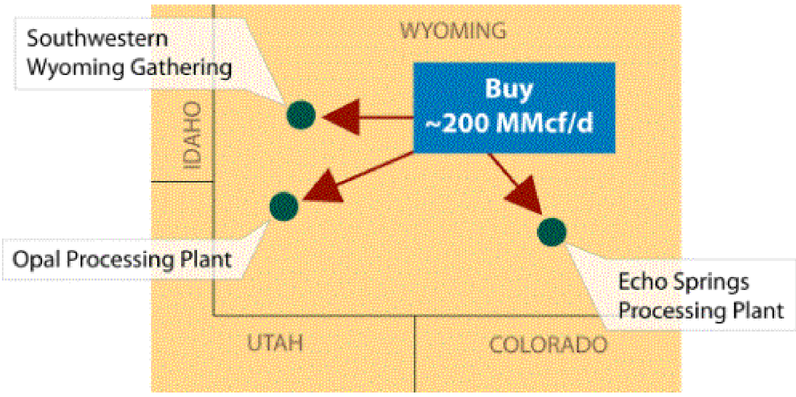


Commodity prices affect Midstream differently



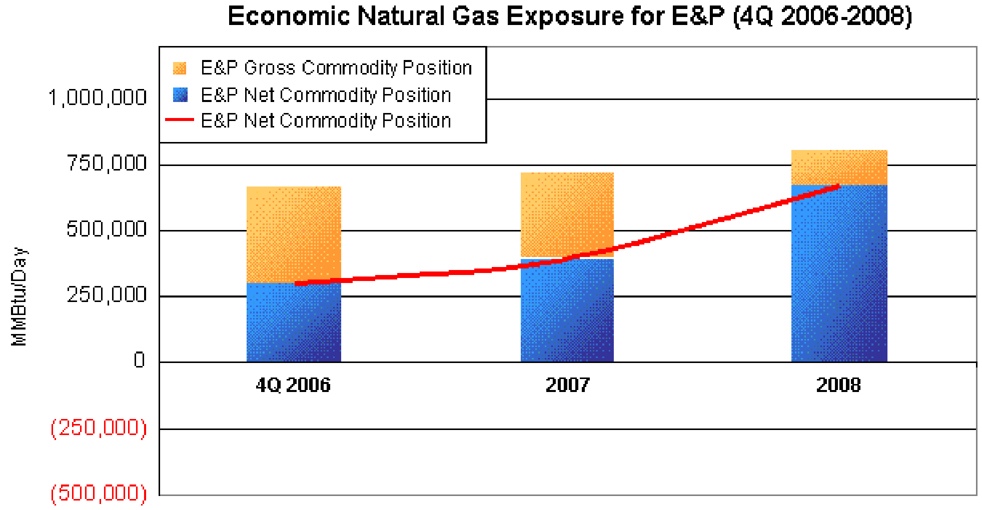
Gas prices based on average *Gas Daily* settle prices at NWP, Wyoming. NGL prices based on composition weighted average of Mont Belvieu daily liquids prices; does not include fuel or T&F. Oil prices are based on average of daily NYMEX prompt settle prices.

Current Rockies price softness benefits our Midstream



- We're a purchaser of Rockies gas to fuel our processing business
- In strong crude market, lower gas prices dramatically improve the margins for our Midstream business

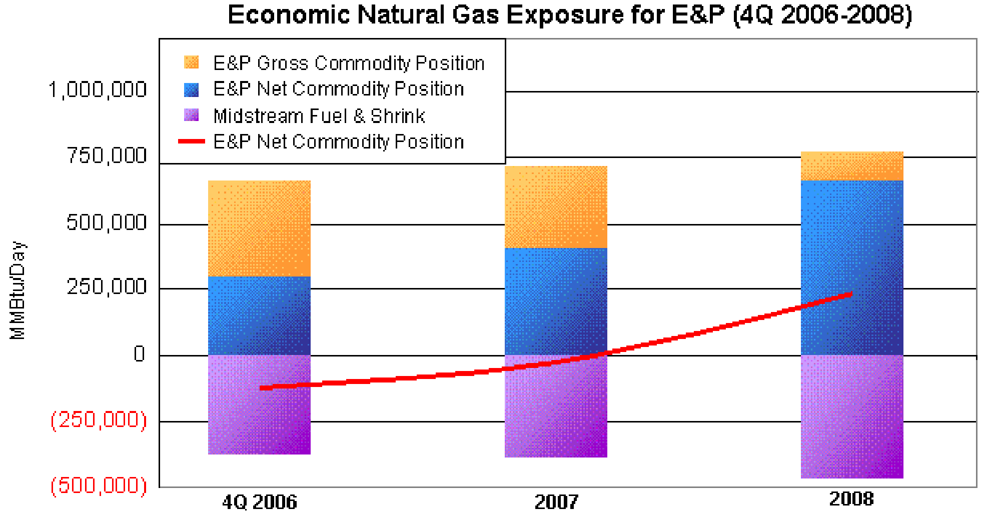
E&P Business creates net long position…



- All values are undiscounted
- International E&P volumes are not included
- Projected E&P volumes are reduced by 20% for fuel & shrink and production taxes
- Hedges are presented in terms of price exposure. Because some hedges have option characteristics, this volume may be different from notional hedge volumes

…which is offset by Midstream gas use

Williams



- All values are undiscounted
- International E&P volumes are not included
- Projected E&P volumes are reduced by 20% for fuel & shrink and production taxes
- Hedges are presented in terms of price exposure. Because some hedges have option characteristics, this volume may be different from notional hedge volumes

Well-positioned for near- to long-term value creation

- Premier assets that are opportunity rich
- Pursuing growth with discipline
- Solid record of delivering results
- Taking action to drive value creation

Financial Results

Don Chappel
Chief Financial Officer

Financial Results

Williams

Dollars in millions (except per share amounts)	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Income from Continuing Operations	$ 110	$ 5	$ 177	$ 249
(Loss) from Discontinued Operations	(4)	(1)	(15)	(2)
Net Income	$ 106	$ 4	$ 162	$ 247
Net Income/Share	$ 0.18	$ 0.01	$ 0.27	$ 0.42
Recurring Income (Loss) from Cont. Ops./Share	$ 0.19	$ (0.01)	$ 0.60	$ 0.44
Recurring Income from Continuing Operations After MTM Adjustments/Share	**$ 0.28**	**$ 0.22**	**$ 0.87**	**$ 0.60**

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)	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Income from Continuing Operations	$ 110	$ 5	$ 177	$ 249
Nonrecurring Items				
Regulatory & Litigation Contingencies				
Settlements & Related Costs	10	-	253	18
Debt Retirement Expense	-	-	31	-
Impairments/Losses/Write-offs/Contingency Adj.	(8)	19	(8)	72
(Income)/expense related to prior periods	11	(14)	4	(42)
Gains on sale of assets	(8)	(22)	(15)	(38)
Other – Net	-	1	1	3
Total Nonrecurring Items	5	(16)	266	13
Tax effects of adjustments	(2)	6	(81)	(2)
Recurring Income (Loss) from Cont. Ops. Avail to Com.	$ 113	$ (5)	$ 362	$ 260
Recurring Income (Loss) from Continuing Ops./Share	$ 0.19	$(0.01)	$ 0.60	$ 0.44

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.

Financial Results

Recurring Income from Cont. Ops. After MTM Adjustment

Williams

Dollars in millions (except per share amounts)	3rd Quarter		YTD	
	2006	2005	2006	2005
Recurring Inc. (Loss) from Cont. Ops. Avail. to Common	$ 113	$ (5)	$ 362	$ 260
Recurring Diluted Earnings (Loss) per Common Share	$ 0.19	$(0.01)	$ 0.60	$ 0.44
Mark-to-Market (MTM) adjustments for Power:				
Reverse forward unrealized MTM (gains)/losses	$ 16	$ 141	$ 11	$ (102)
Add realized gains from MTM previously recognized	80	72	257	262
Total MTM Adjustments	96	213	268	160
Tax Effect of Total MTM Adjustments	(37)	(83)	(103)	(62)
After-Tax MTM Adjustments	$ 59	$ 130	$ 165	$ 98
Recurring Inc. from Cont. Ops. Avail. to Common Shareholders after MTM adjustments	$ 172	$ 125	$ 527	$ 358
Recurring Diluted Earnings Per Share after MTM adjustments	$ 0.28	$ 0.22	$ 0.87	$ 0.60

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

Third Quarter Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production (see slide 54)	$145	$159	$145	$137
Midstream Gas & Liquids (see slide 65)	212	121	222	121
Gas Pipeline (see slide 75)	109	161	109	147
Power (see slide 82)	(70)	(226)	(79)	(226)
Other	-	(10)	-	(10)
Segment Profit	$396	$205	$397	$169
MTM Adjustments - Power			96	213
Segment Profit after MTM Adjustments			**$493**	**$382**
Memo:				
Power after MTM Adjustments			$17	($13)

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.

2006 YTD Segment Profit

Dollars in millions	Reported 2006	Reported 2005	Recurring 2006	Recurring 2005
Exploration & Production (see slide 54)	$412	$381	$412	$352
Midstream Gas & Liquids (see slide 65)	494	359	566	359
Gas Pipeline (see slide 75)	366	493	364	444
Power (see slide 82)	(172)	(187)	(181)	(162)
Other	1	(75)	1	(23)
Segment Profit	$1,101	$971	$1,162	$970
MTM Adjustments - Power			268	160
Segment Profit after MTM Adjustments			**$1,430**	**$1,130**
Memo:				
Power after MTM Adjustments			$87	($2)

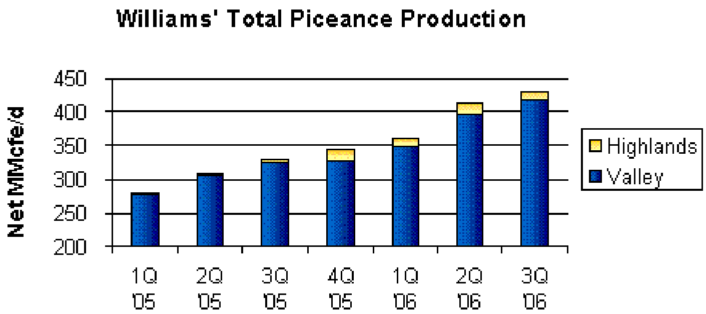
A more detailed schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com and at the end of this presentation.

Exploration & Production

Ralph Hill
President

Piceance Production Growth

- Up 101 MMcfed or 31% over a year ago
- 24 total rigs currently operating in Valley and Highlands compared to 15 a year ago
- 2 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



Piceance Highlands – Building Momentum

- 39 wells spud year to date
- 24 MMcfed current net production, up from 5 MMcfed year ago
- Averaged 8 rigs operating during 3Q06
- Major road, pipeline, and facilities under construction
- Working towards year round drilling

Piceance Basin: Highlands Ownership Position

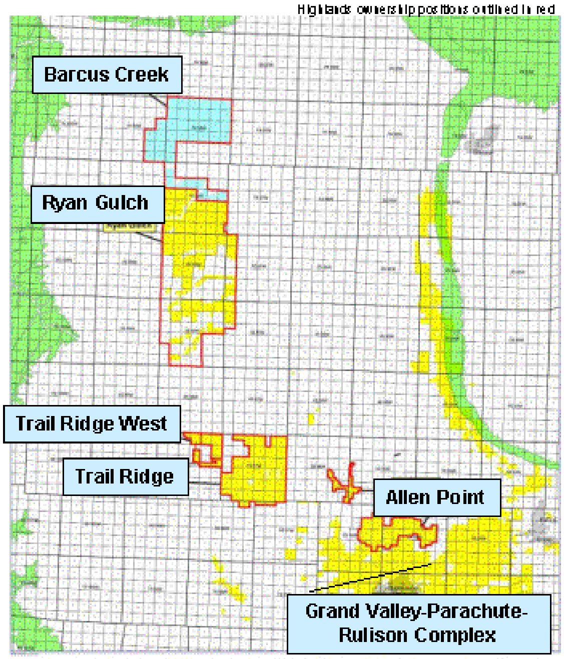
Farm-In Deals

Ryan Gulch
- Earned 16,000 net acres by drilling 6 wells

Allen Point
- Earned 6,200 net acres by drilling 6 wells

Barcus Creek
- Newly added farm-in deal

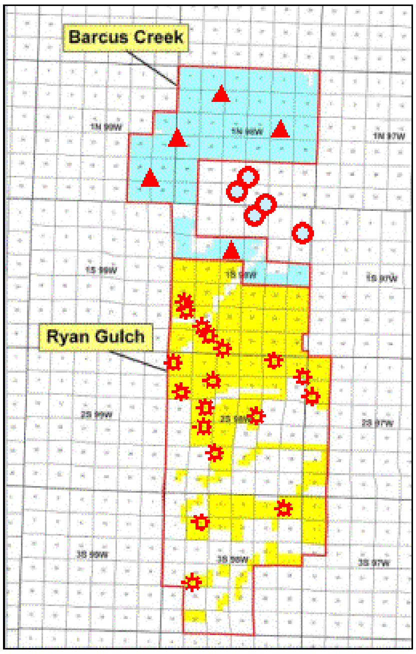
Highlands ownership positions outlined in red



Barcus Creek Farm-In Deal

Williams

- Direct bolt-on to Ryan Gulch Project
- Targets Williams Fork Formation
- Drill 5 wells by October 2007, with first well currently drilling
- Earn 45% working interest in ~25,000 gross acres (~11,000 acres net to Williams)
- 87.5% NRI
- 45% working interest in future gas gathering/processing systems
- 600+ potential drill locations (40-acre density)
- Williams to operate



Ryan Gulch Wells

Barcus Creek Earning Wells

Industry wells

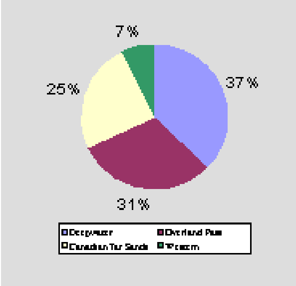
Midstream

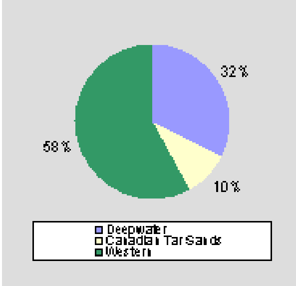
Alan Armstrong
President

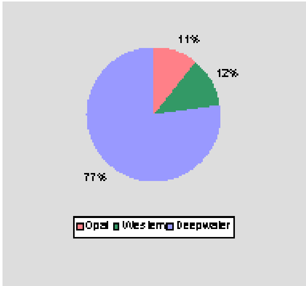
Midstream

Significant Progress Made on Growth Projects

In Development/Proposal	Under Negotiation	In Guidance
2006 **2007 2008+**	2006 **2007 2008+**	2006 **2007 2008+**
Spending $900MM–1,500MM	Spending $300MM–500MM	Spending $800-900MM







Major Growth Projects Included in Guidance ($ Millions)

Project Name – In Service Date	2006	2007	2008
Opal TXP IV (1Q 2006)	$33	-	-
Opal TXP V (2Q 2007)	$50	$10	-
Blind Faith (2Q 2008)	$70	$95	$10
Other Wyoming G&P (4Q '07 + Various)	-	$50	$30
Western Gulf Deepwater Expansion (3Q '09)	$10	$185	$180

Midstream

Deepwater Lower Tertiary Discoveries

2006-08 Consolidated Outlook

Don Chappel
Chief Financial Officer

Consolidated

2006 Forecast Guidance

Dollars in millions, except per-share amounts	Nov 2 Guidance	Aug 3 Guidance
Segment profit before MTM adjustment	$1,430 - $1,645	$1,355 - $1,675
Net Interest Expense	(660) - (690)	(670) - (710)
Other (Primarily General Corp. Costs)	(115) - (135)	(105) - (125)
Securities Litigation Settlement & Related Costs	(165)	(162)
Pretax Income	490 - 655	418 - 678
Provision for Income Tax	(225) - (300)	(185) - (295)
Income from Continuing Ops	265 - 355	233 - 383
Income/(Loss) from Discontinued Ops	(20) - 0	(5) - 0
Net Income	$245 - 355	$228 - 383
Diluted EPS	$0.40 - $0.58	$0.37 - $0.63
Recurring Income from Cont. Ops	$450 - $540	$414 - $564
Diluted EPS – Recurring	$0.74 - $0.89	$0.68 - $0.92
Diluted EPS – Recurring After MTM Adj. [1]	**$1.05 - $1.20**	**$0.95 - $1.20**

[1] *Includes MTM adjustment of $315 million (pretax) in Nov 2 guidance and $275 million (pretax) in Aug 3 guidance*
Note: Fully diluted shares of 610 million

2006-08 Segment Profit

Dollars in millions	2006	2007	2008
Exploration & Production	$550 - 600 *650*	$825 - 950	$1,025 - 1,175
Midstream	675 - 750 [1] *550 - 675 [1]*	500 - 750	550 - 800
Gas Pipeline	475 - 500 *520*	585 - 655	590 - 665
Power	(240) - (190) *(200) - (150)*	(75) - 25 *(175) - (75)*	(150) - 0 *(155) - (5)*
Other / Corp. / Rounding	(30) - (15) *(20)*	10 - (30)	(15) - 35
Total Reported Before MTM Adj.	$1,430 - 1,645 *$1,355 - 1,675*	$1,845 - 2,350 *$1,745 - 2,250*	$2,000 - 2,675 *$1,995 - 2,670*
MTM Adjustment	315 *275*	125 *225*	200 *205*
Total Reported After MTM Adj.	$1,745 - 1,960 *$1,630 - 1,950*	$1,970 - 2,475	$2,200 - 2,875
Nonrecurring Items	61 *60*	-	-
Total Recurring After MTM Adj.	**$1,806 - 2,021** *$1,690 - 2,010*	**$1,970 - 2,475**	**$2,200 - 2,875**

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

[1] *Includes nonrecurring litigation accrual of $70 million in Nov 2 guidance and $68 million in Aug 3 guidance*

Note: If guidance has changed, previous guidance from 8/3/06 is shown in italics directly below

Consolidated

2006-08 Capital Expenditures

Dollars in millions	2006	2007	2008
Exploration & Prod.	$1,150 - 1,250	$1,150 - 1,250	$1,150 - 1,300
Midstream	250 - 260 *280 - 300*	420 - 460 *230 - 270*	260 - 300 *70 - 90*
Gas Pipeline	745 - 815	370 - 470	340 - 440
Power	-	-	-
Other/Corporate	10 - 30	10 - 30	10 - 30
Total	$2,175 - 2,375 *$2,200 - 2,400*	$2,000 - 2,200 *$1,775 - 1,975*	$1,800 - 2,050 *$1,575 - 1,825*

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

2006-08 Outlook

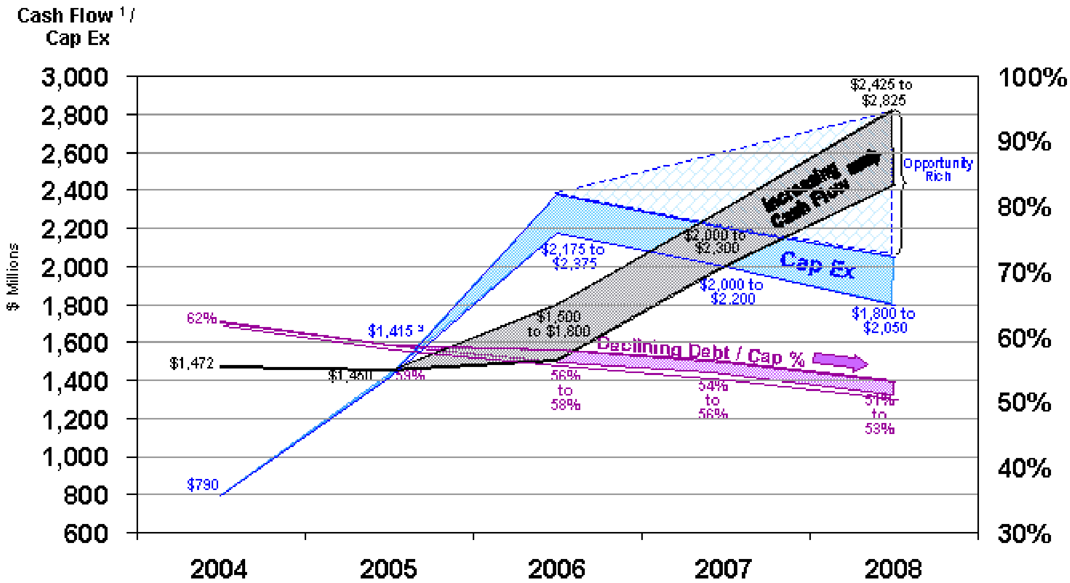
Dollars in millions	2006	2007	2008
Segment Profit			
Reported After MTM Adj.	$1,745 - 1,960 *$1,630 - 1,950*	$ 1,970 - 2,475	$2,200 - 2,875
Recurring After MTM Adj.	1,806 - 2,021 *1,690 - 2,010*	1,970 - 2,475	2,200 - 2,875
DD&A	840 - 920 *820 - 920*	960 - 1,060 *930 - 1,030*	1,050 - 1,150 *1,010 - 1,110*
Cash Flow from Ops.[1]	1,500 - 1,800	2,000 - 2,300	2,425 - 2,825
Capital Expenditures	2,175 - 2,375 *2,200 - 2,400*	2,000 - 2,200 *1,775 - 1,975*	1,800 - 2,050 *1,575 - 1,825*
Operating Free Cash Flow[2]	(675) - (575) *(700) - (600)*	0 - 100 *225 - 325*	625 - 775 *850 - 1,000*

[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 8/3/06 is shown in italics directly below

Consolidated

Strong Operating Cash Flow Growth & Increasing Investment Opportunities



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

Financial Strategy/Key Points

- Drive/enable sustainable growth in EVA® / shareholder value
- Strategy to accelerate delivery of MLP benefits 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

Well-positioned for near- to long-term value creation

Premier assets that are opportunity rich

Pursuing growth with discipline

Solid record of delivering results

Taking action to drive value creation

Q&A

Williams

Non-GAAP Reconciliations

Non-GAAP Disclaimer

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

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

Non-GAAP Reconciliation Schedule

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

(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 3rd Qtr	2006 Year
Income (loss) from continuing operations available to common stockholders	$202.2	$46.7	$5.7	$60.8	$315.4	$111.1	$(40.0)	$101.1	$172.2
Income (loss) from continuing operations - diluted earnings (loss) per common share	$0.34	$0.07	$0.01	$0.11	$0.53	$0.22	$(0.13)	$0.16	$0.28
Nonrecurring items:									
Exploration & Production									
Gains on sales of E&P properties	(7.8)	-	(20.7)	-	(28.4)	-	-	-	-
Loss provision related to an ownership dispute	0.0	-	-	-	0.0	-	-	-	-
Total Exploration & Production nonrecurring items	(7.8)	-	(20.7)	-	(28.4)	-	-	-	-
Gas Pipeline									
Prior period liability corrections - TGPL	(13.1)	(4.6)	-	-	(17.7)	-	-	-	-
Prior period depreciation 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	-	-	-	27.2	27.2	-	-	-	-
Accrual of contingent refund obligation - TGPL	-	-	-	9.8	9.8	-	-	-	-
Reversal of litigation contingency due to favorable ruling - TGPL	-	-	-	-	-	(1.9)	-	-	(1.9)
Total Gas Pipeline nonrecurring items	(13.1)	(21.7)	(14.2)	37.0	[illegible]	(1.9)	-	-	(1.9)
Midstream Gas & Liquids									
Gains on sales of MGL properties	-	-	-	-	-	-	-	(7.8)	(7.8)
Adjustment of accounts payable accrual	-	-	-	-	-	-	-	(0.4)	(0.4)
Losses on asset retirements and abandonments	-	-	-	-	-	-	-	5.2	5.2
Accrual for Gulf Liquids litigation contingency	-	-	-	-	-	-	68.0	2.4	70.4
Settlement of an international contract dispute	-	-	-	-	-	(4.2)	-	-	(4.2)
Total Midstream Gas & Liquids nonrecurring items	-	-	-	-	-	(4.2)	68.0	[illegible]	[illegible]
Power									
Reduction of contingent obligations associated with our former distributive power generation business	-	-	-	-	-	-	-	(12.7)	(12.7)
Accrual for a regulatory settlement [1]	4.4	-	-	-	4.4	-	-	-	-
Accrual for litigation contingencies [1]	-	13.1	9.4	60.7	83.2	-	-	3.5	3.5
Impairment of [illegible]	-	-	-	23.0	23.0	-	-	-	-
Prior period correction	6.8	-	-	-	6.8	-	-	-	-
Total Power nonrecurring items	11.2	13.1	9.4	83.7	117.4	-	-	(9.2)	(9.2)
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 [illegible]	-	-	-	(9.0)	(9.0)	-	-	-	-
Total Other nonrecurring items	-	53.1	-	29.1	82.2	-	-	-	-
Nonrecurring items included in segment profit (loss)	(9.7)	44.5	(25.5)	150.8	[illegible]	(6.1)	68.0	[illegible]	[illegible]
Nonrecurring items below segment profit (loss)									
Gain on sale of remaining interest in Seminole Pipeline and MAPL (Investing income / loss - Midstream)	-	(5.4)	-	-	(5.4)	-	-	-	-
Loss provision related to an ownership dispute - interest component (Interest accrued - Exploration & Production)	3.7	-	-	-	3.7	-	-	-	-
Directors and officers insurance policy adjustment (General corporate expenses - Corporate)	-	-	11.8	-	11.8	-	-	-	-
Loss provision related to ERISA litigation settlement (Other income (expense) - net - Corporate)	-	-	5.0	-	5.0	-	-	-	-
Securities litigation settlement and related costs [1]	-	-	-	8.4	8.4	1.2	160.7	3.4	165.3
Reversal of interest accrual related to reversal of litigation contingency noted above (Interest accrued - Gas Pipeline - TGPL)	-	-	-	-	-	(1.4)	-	-	(1.4)
Early debt retirement costs (Corporate and Exploration & Production)	-	-	-	-	-	27.6 [2]	3.8	-	31.4
Gain on sale of [illegible] shares (Investing income / loss - Other)	-	-	-	-	-	(4.7)	-	-	(4.7)
Interest related to Gulf Liquids litigation contingency (Interest accrued - Midstream)	-	-	-	-	-	-	29.0	6.4	35.4
	3.7	(5.4)	16.8	8.4	23.5	22.7	193.5	9.8	226.0
Total nonrecurring items	(6.0)	39.1	(8.7)	159.2	[illegible]	16.6	261.5	[illegible]	[illegible]
Tax effect for above items [1]	(3.0)	16.7	(4.1)	48.8	[illegible]	[illegible]	76.6	[illegible]	[illegible]
Adjustment for nonrecurring excess deferred tax benefit	-	-	-	(20.2)	(20.2)	-	-	-	-
Recurring income (loss) from continuing operations available to common stockholders	[illegible]	$69.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Recurring diluted earnings (loss) per common share	[illegible]	[illegible]	[illegible]	$0.28	[illegible]	[illegible]	[illegible]	$0.16	[illegible]
Weighted-average shares - diluted (thousands)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[1] The tax effect on $4 million of the accrual for a regulatory settlement in 1st quarter 2005 and [illegible] million and $91 million of the accrual for litigation contingencies in 2nd quarter 2005 and 4th quarter 2005, respectively. The tax rate applied to [illegible] international contract dispute settlement in 1st quarter 2006 is 36%. 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.

Non-GAAP Reconciliation Schedule

(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 3rd Qtr	2006 Year
Segment profit (loss):									
Exploration & Production	$ 103.7	$ 118.3	$ 158.8	$ 206.4	$ 587.2	$ 147.6	$ 119.8	$ 144.5	$ 411.9
Gas Pipeline	167.4	164.5	161.1	92.8	585.8	134.7	122.7	109.0	366.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	151.5	130.7	212.2	494.4
Power	114.1	(75.0)	(226.4)	(69.4)	(256.7)	(22.5)	(79.6)	(69.7)	(171.8)
Other	(4.1)	(60.5)	(10.1)	(30.3)	(105.0)	1.0	(0.7)	(0.2)	0.1
Total segment profit	**$ 509.7**	**$ 256.4**	**$ 204.5**	**$ 311.9**	**$ 1,282.5**	**$ 412.3**	**$ 292.9**	**$ 395.8**	**$ 1,101.0**
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	10.3	72.0
Power	11.4	13.1	0.4	91.7	116.6	-	-	(9.2)	(9.2)
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**	**$ 1.1**	**$ 60.8**
Recurring segment profit (loss):									
Exploration & Production	96.1	118.3	137.1	206.4	557.9	147.6	119.8	144.5	411.9
Gas Pipeline	154.3	142.8	146.9	130.1	574.1	132.7	122.7	109.0	364.4
Midstream Gas & Liquids	128.6	109.1	121.1	112.4	471.2	145.2	198.7	222.5	566.4
Power	125.5	(61.9)	(226.0)	22.3	(140.1)	(22.5)	(79.6)	(78.9)	(181.0)
Other	(4.1)	(7.4)	(10.1)	(1.2)	(22.8)	1.0	(0.7)	(0.2)	0.1
Total recurring segment profit	**$ 500.4**	**$ 300.9**	**$ 169.0**	**$ 470.0**	**$ 1,440.3**	**$ 404.0**	**$ 360.9**	**$ 396.9**	**$ 1,161.8**

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	2006 2Q	2006 3Q	2006 4Q	2006 Year
Recurring income from cont. ops available to common shareholders	$ 136	$ 113	$ 113		$ 362
Recurring diluted earnings per common share	$ 0.23	$ 0.19	$ 0.19		$ 0.60
Mark-to-Market (MTM) adjustments:					
Reverse forward unrealized MTM gains/losses	(43)	38	16		11
Add realized gains/losses from MTM previously recognized	77	100	80		257
Total MTM adjustments	34	138	96		268
Tax effect of total MTM adjustments	13	53	37		103
After tax MTM adjustments	21	85	59		165
Recurring income from cont. ops available to common shareholders after MTM adjust.	$ 157	$ 198	$ 172		$ 527
Recurring diluted earnings per share after MTM adj.	$ 0.26	$ 0.33	$ 0.28		$ 0.87
weighted average shares - diluted (thousands)	607,073	595,561	609,062		608,045

	2005 1Q	2005 2Q	2005 3Q	2005 4Q	2005 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

Non-GAAP Reconciliation

EBITDA Reconciliation

Williams

Dollars in millions	3Q06	YTD
Net Income	$ 106	$ 162
Loss from Discontinued Operations	4	15
Net Interest Expense	158	495
DD&A	220	628
Provision for Income Taxes	100	190
EBITDA	$ 588	$ 1,490

Non-GAAP Reconciliation

3Q 2006 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Corp/ Other	Total
Segment Profit (Loss)	$ 145	$ 212	$ 109	$ (70)	$ -	$ 396
DD&A	95	50	70	2	3	220
Segment Profit before DDA	**$ 240**	**$ 262**	**$ 179**	**$ (68)**	**$ 3**	**$ 616**
General Corporate Expense						(35)
Securities litigation settlement and related costs						(3)
Investing Income*						20
Other Income						(10)
TOTAL						$ 588

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

Non-GAAP Reconciliation

YTD 2006 Segment Contribution

Dollars in Millions

	E&P	Midstream	Gas Pipeline	Power	Corp/ Other	Total
Segment Profit (Loss)	$ 412	$ 494	$ 366	$ (172)	$ 1	**$ 1,101**
DD&A	252	149	209	9	9	**628**
Segment Profit before DDA	**$ 664**	**$ 643**	**$ 575**	**$ (163)**	**$ 10**	**$ 1,729**
General Corporate Expense						**(99)**
Securities litigation settlement and related costs						**(165)**
Investing Income*						**66**
Other Income						**(41)**
TOTAL						**$ 1,490**

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

2006 Forecast EBITDA Reconciliation

Dollars in millions	Nov 4 Guidance	Aug 3 Guidance
Net Income	**$245 - 355**	$228 - 383
Loss from Disc. Ops.	20 - 0	5 - 0
Net Interest	660 - 690	670 - 710
DD&A	840 - 920	820 - 920
Provision for Income Taxes	225 - 300	185 - 295
Other/Rounding	10	(8)
EBITDA	**$2,000 - 2,275**	$1,900 - 2,300
MTM Adjustments	315	275
EBITDA - After MTM Adj.	**$2,315 - 2,590**	$2,175 - 2,575

2006 Forecast Segment Contribution

Dollars in millions	E&P	Midstream	Gas Pipeline	Power [1]	Corp/ Other	Total
Segment Profit / (Loss)	$550 - 600	$675 - 750	$475 - 500	$(240) - (190)	$(30) - (15)	$1,430 - 1,645
DD&A	360 - 400	190 - 200	280 - 300	10 - 15	0 - 5	840 - 920
Seg Profit/(Loss) Before DD&A	$910 - 1,000	$865 - 950	$755 - 800	$(230) - (175)	$(30) - (10)	$2,270 - 2,565
Other (Primarily General Corporate Expense & Investing Income)						(115) - (135)
Securities Litigation Settlement and Related Costs						(165)
Rounding						10
TOTAL						$2,000 - 2,275

[1] Segment Profit is prior to MTM adjustments

2006 Forecast Guidance Contribution

Dollars in millions, except per-share amounts	Nov 2 Guidance	Aug 3 Guidance
Net Income	**$245 - 355**	**$228 - 383**
Less: Discontinued Operations (Loss)	(20) - 0	(5) - 0
Income from Continuing Ops	**$265 - 355**	**$233 - 383**
Non-Recurring Items (Pretax)	266	261
Less Taxes	81	80
Non-Recurring After Tax	185	181
Recurring Income from Cont. Ops	**$450 - 540**	**$414 - 564**
Recurring EPS	**$0.74 - $0.89**	**$0.68 - $0.92**
Mark-to-Market Adjustment (Pretax)	315	275
Less Taxes @ 39%	123	107
Mark-to-Market Adjust. After Tax	192	168
Inc. from Cont. Ops after MTM Adj.	**$642 - 732**	**$582 - 732**
Inc. from Cont. Ops after MTM Adj. EPS	**$1.05 - $1.20**	**$0.95 - $1.20**

Appendix

Exploration & Production

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
- New areas significantly contributing
- Experienced and talented work force

Segment Profit – Exploration & Production

Dollars in millions	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$145	$159	$412	$381
Nonrecurring				
Gains on sales of assets	-	(22)	-	(29)
Recurring segment profit	$145	$137	$412	$352

3Q06 to 3Q05 financial highlights:

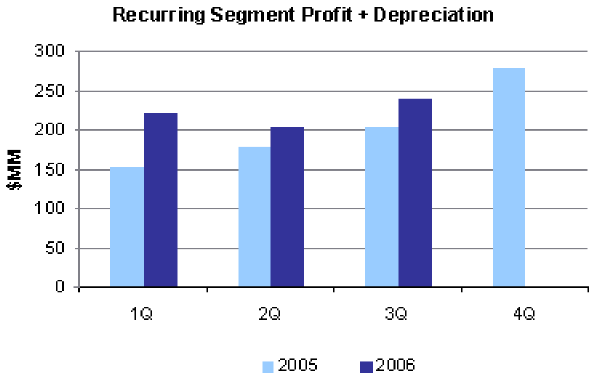
- 21.8% volume production growth
- Sequential volume growth of 5.7% and 20.5% segment profit growth over second quarter
- $40 million negative hedge impact in 3Q06

2006 YTD to 2005 YTD financial highlights:

- 19.7% volume production growth
- 17% recurring segment profit growth
- $173 million negative hedge impact year to date

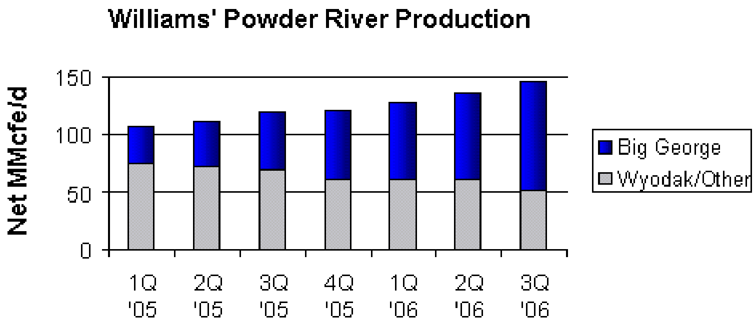
2006 Accomplishments

- 3Q06 production up 22%, 149 MMcfed since 3Q05
- Surpassed 800MMcfed
- 8 H&P rigs drilling
- Additional 4,080 acres Piceance Valley 10-acre spacing approved
- Big George/Powder River volumes continue impressive growth
- Barcus Creek farm-in finalized
- Barnett Shale
  - Producing ~16MMcfed
  - ~20,000 net acres under lease or farm-out
- San Juan production at record levels
- International profits increase

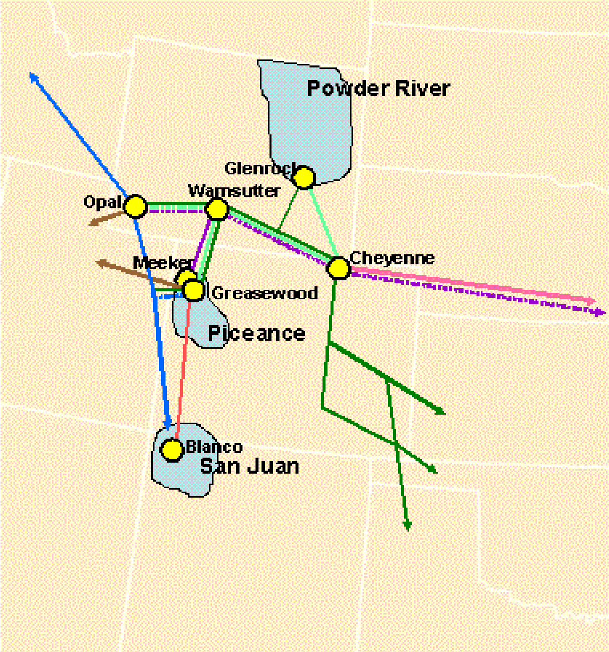


Powder River

- Up 28 MMcfed or 24% over a year ago
- Big George coals driving basin growth
  - Up 80% year over year
  - September vs. June volumes up 12%
- Anadarko assumes outside operations



Rockies Producer Not Rockies Price Taker



Pipes Used to Move Williams Gas

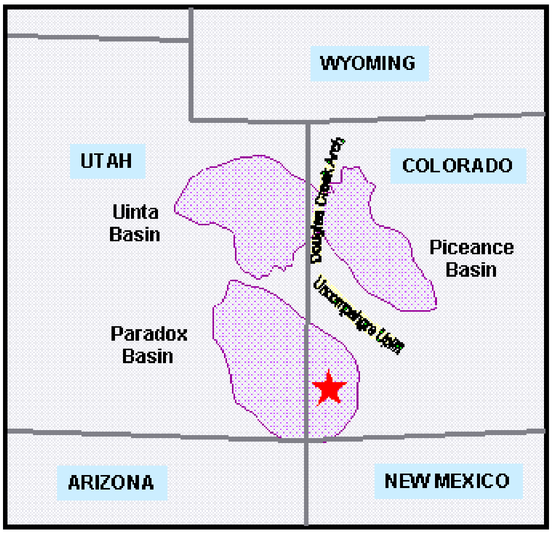
- CIG
- NWPL
- Questar
- Rockies Express
- Trailblazer
- TransColorado
- WIC

Firm Access Under Contract

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

Paradox Basin Project

- Paradox Basin is immediately adjacent to Piceance and Uinta Basins
- Acreage position increased from 30,608 to 74,000 net acres
- Formed large Joint Venture with successful Rocky Mountain independent
- Emerging play targets fractured Gothic Shale Formation
- First of four planned wells to spud in November



Exploration & Production

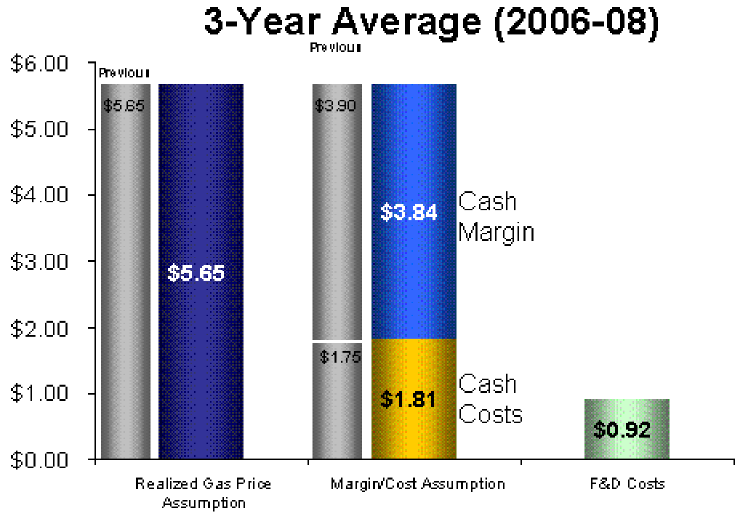
2006-08 Guidance

Dollars in millions	2006	2007	2008
Segment Profit	$550 - 600 *650*	$825 - 950	$1,025 - 1,175
Annual DD&A	360 - 400	455 - 505	500 - 550
Segment Profit + DD&A	$910 - 1,000 *910-1050*	$1,280 - 1,455	$1,525 - 1,725
Capital Spending	$1,150 - 1,250	$1,150 - 1,250	$1,150 - 1,300
Production (MMcfe/d)	770 - 845	905 - 1,005	990 - 1,140

Unhedged Price Assumption ($/Mcf)			
Average San Juan/Rockies Price	$5.87	$6.09	$6.10
Average Mid-continent Price	$6.01	$6.75	$6.77
NYMEX	$7.13	$7.00	$7.00

Note: 2006-08 hedge information included in Appendix.
Note: If guidance has changed, previous guidance from 8/3/06 is shown in italics directly below.

Cash Margin Analysis



Reflective of core basins

- *$5.65 is after hedging and includes average basin market price of $6.21 before hedging*
- *Cash costs include LOE, G&A, taxes and gathering*
- *F&D costs include acquisition and development expenditures/proved reserves ('03-'05 average)*

3Q Net Realized Price Summary

	Unhedged	Hedge
Market Price:		
NYMEX	$6.25 - $7.00	$4.38
NYMEX collars		0.17
Basis Differential	(0.80) - (1.05)	(0.55)
Net basin market price	$5.20 - $6.20	$3.99
Net basin market price	**$5.20 - $6.20**	**$3.99**
Fuel & Shrinkage/Gathering/ Transportation	(0.60) - (0.80)	(0.60) - (0.70)
Net Price	**$4.40 - $5.60**	**$3.29 - $3.39**
Quarter Volume Totals	(qtr daily volumes - qtr daily volumes) x (92/1000)	(qtr daily hedge volumes) x (92/1000)
Net Gas Revenue	=(unhedged volumes x net price)	=(hedged volumes x net hedge price)

** Corrected from original edition*

Exploration & Production

2006-08 Hedge Update

Dollars in millions	**4Q 2006**	**2007**	**2008**
Fixed Price at the basin:			
Volume (MMcf/d)	288	172	73
Average Price ($/Mcf)	$3.89	$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	$6.20 - 9.57
Mid-Continent			
Volume (MMcf/d)	-	75	5
Price ($/Mcf)		$6.82 - $10.80	$7.23 - $8.62

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

Midstream

Key Points

- Focused on our strategy of reliability
- Base business continues to generate healthy returns and free cash flows
- NGL margins again exceed historic levels – cushioning enterprise impact of lower gas prices
- Forecast margins in line with current gas/crude pricing relationship
- Progress continues on deepwater expansions
- Western growth opportunities abound

Financial Results

Segment Profit - Midstream

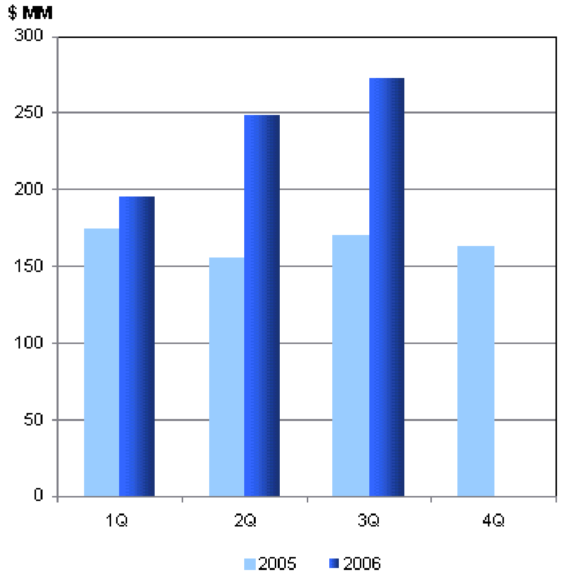
Dollars in millions	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$212	$121	$494	$359
Nonrecurring				
Accrual for Gulf Liquids litigation	2	-	70	-
International Contract Settlement	-	-	(6)	-
Asset sales, retirement & abandonment	(3)	-	(3)	-
Accounts payable accrual adjustment	11	-	11	-
Recurring segment profit	$222	$121	$566	$359

- **3Q06 to 3Q05 financial highlights:**
  - Record NGL unit margins
  - Higher fee revenue
  - Higher Canadian performance
  - Increased operating expenses
- **2006 YTD to 2005 YTD financial highlights:**
  - Higher NGL unit margins
  - Higher fee revenue
  - Increased operating expenses

2006 Accomplishments

- Another record quarter
- NGL unit margins at new records
- Canadian Oil Sands YTD ’06 vs YTD ’05:
  - + 37% in composite unit margins
  - + 86% in production volume
- Western Gulf Deepwater Expansions
- Long term processing agreement on Discovery
- Opal TXP-V construction on track

Recurring Segment Profit + Depreciation



Midstream

2006-08 Guidance

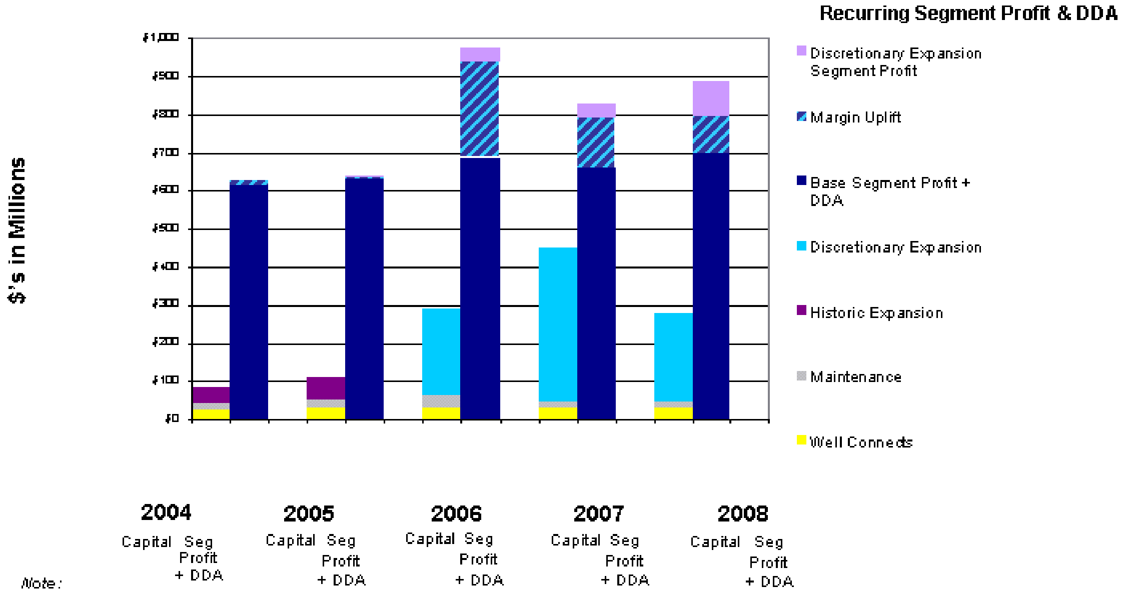
Dollars in millions	2006	2007	2008
Segment Profit	$675 - 750 *550 - 675*	$500 - 750	$550 - 800
Annual DD&A	190 - 200	200 - 210	210 – 220
Segment Profit + DD&A	$865 - 950 *740 - 875*	$700 - 960	$760 - 1,020
Capital Spending	$250 – 260 *280 – 300*	$420 - 460 *230 – 270*	$260 - 300 *70 - 90*

Un-Hedged Price Assumptions	**2006**	**2007**	**2008**
NYMEX Natural Gas ($/Mcf)	**$7.13**	**$7.00**	**$7.00**
NYMEX Oil ($/bbl)	**$67**	**$55 - $69**	**$55 - $69**
Net Liquid Margin (cents/gallon)	**31.0**	**24.0**	**26.0**

Note: Guidance is stated on a non-recurring basis. If guidance has changed, previous guidance from 08/03/2006 is shown in italics directly below.

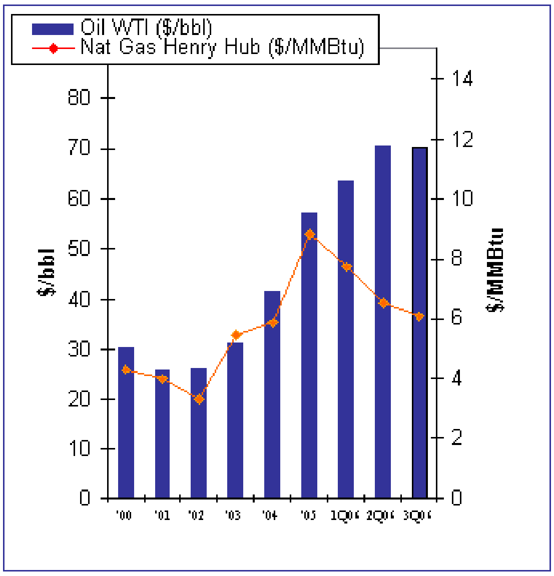
Midstream

Free Cash Flow - Forecast

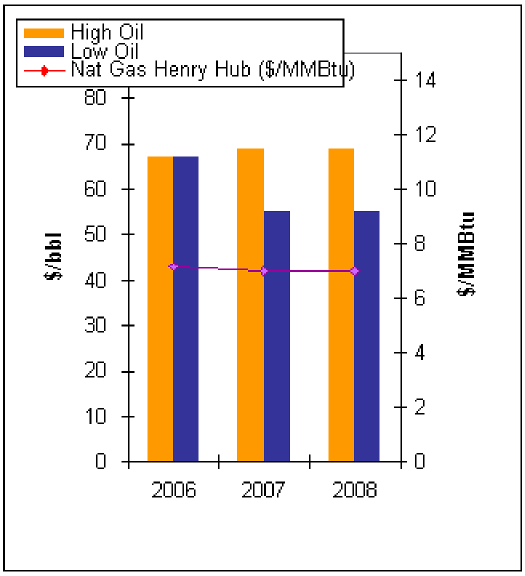


Note:
- *Segment Profit is stated on a recurring basis. Segment Profit for 2004 has been restated to reflect reclassifications*
- *Segment Profit + DDA and Capital Spending reflect midpoint of ranges.*
- *Margin uplift represents actual realized margin for base business in excess of five year (4Q01-3Q06) average margin of 14.9 cpg.*

Pricing Assumptions Included in Guidance



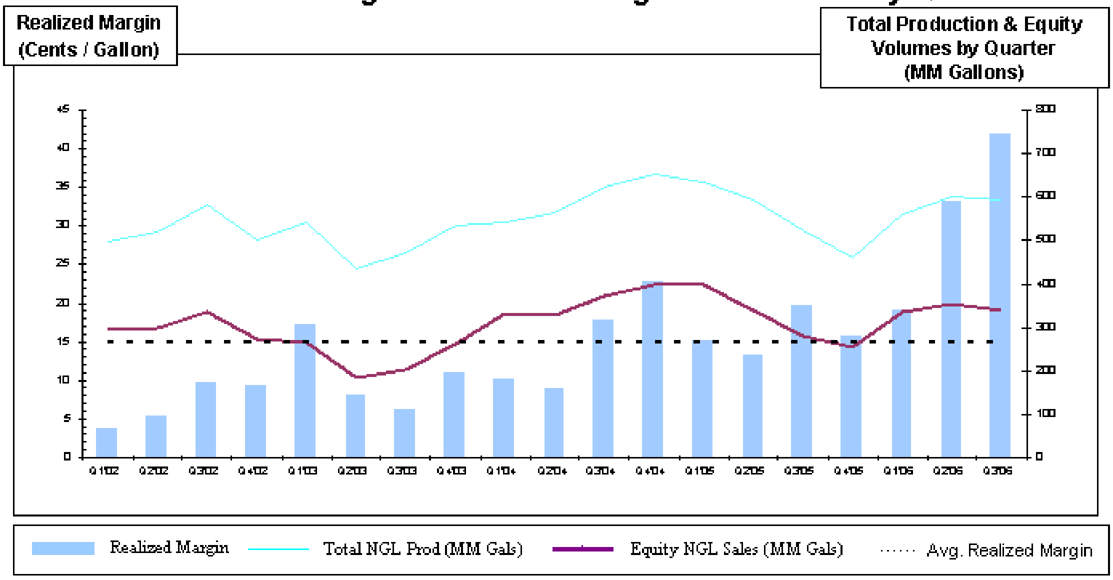
Historic Prices



Guidance Pricing Assumptions

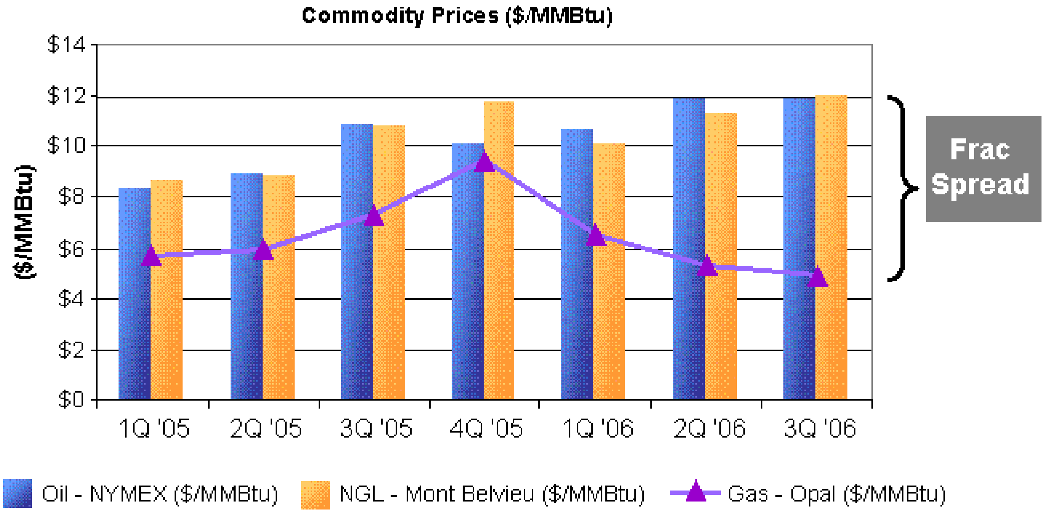
Margins Above Average

Domestic NGL Average Realized Net Margin and Volumes by Quarter



Note: Actual realized margins, does not include Discovery volumes. Five year average of 14.9 cpg is calculated for the period 4Q01-3Q06.

Frac Spread Drivers



Gas prices based on average *Gas Daily* settle prices at NWP, Wyoming. NGL prices based on composition weighted average of Mont Belvieu daily liquids prices; does not include fuel or T&F. Oil prices are based on average of daily NYMEX prompt settle prices.

YTD Equity NGL Margins by Region

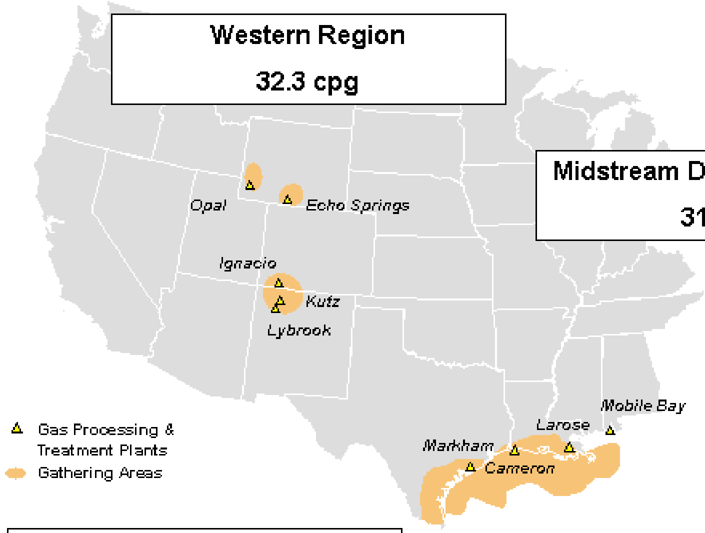
Williams

Western Region

32.3 cpg

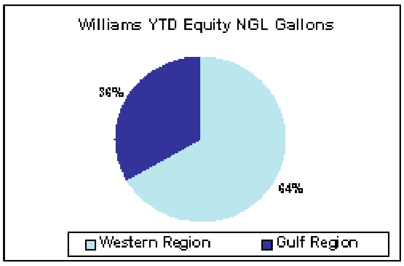
Midstream Domestic Average

31.4 cpg



Gulf Coast Region

29.8 cpg



Gas Pipeline

Key Points

- 26-inch Replacement project construction substantially complete in November
- Growth projects progressing
- Rate Cases Progressing
- Segment Profit remains on target

Segment Profit – Gas Pipeline

Dollars in millions	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Segment Profit	$109	$161	$366	$493
Nonrecurring				
1999 Fuel Tracker adjustment	-	(14)	-	(14)
Excess royalty reserve reversal	-	-	(2)	-
Pension expense reduction	-	-	-	(17)
Adjustment to carrying value of certain liabilities	-	-	-	(18)
Recurring segment profit	$109	$147	$364	$444

- **3Q06 to 3Q05 financial highlights**:
  - Decrease is mainly due to:
    - Higher SG&A costs - $22MM
      - Labor & Benefits
      - Property & Liability Insurance
      - IT Support Costs
    - Higher O&M costs - $4MM
      - Pipeline Safety costs
    - Lower JV Earnings - $8MM
    - Higher DDA - $3MM

- **2006 YTD to 2005 YTD financial highlights:**
  - Decrease is mainly due to:
    - Higher SG&A Costs - $39MM
      - Labor & Benefits
      - Property & Liability Insurance
      - IT Support Costs
    - Higher O&M Costs - $21MM
    - Higher DDA Costs - $10MM
    - Higher Operating Taxes - $7MM

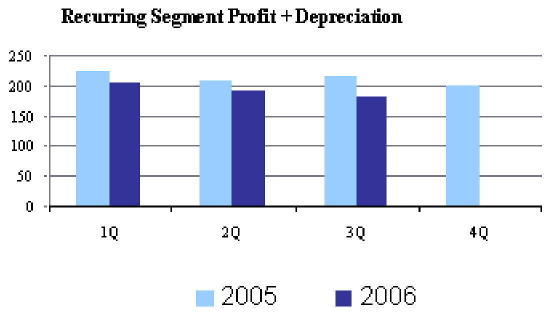
2006 Accomplishments

Northwest

- Parachute Lateral Expansion Project receives FERC approval
- Northwest celebrates 50 years of continuous service
- Northwest filed rate case June 30th, effective Jan 1st 2007

Transco

- Leidy to Long Island Expansion project receives FERC approval
- FERC certificate application filed for Potomac Expansion Project
- Transco filed rate case August 31st, effective March 1st 2007



Gas Pipeline

2006-08 Guidance

Dollars in millions

	2006	2007	2008
Segment Profit	$475 - 500 *475-520*	$585 - 655	$590 - 665
Annual DD&A	280 - 300	305 - 325 *290-310*	325 - 350 *295-315*
Segment Profit + DD&A	$755 - 800 *755-820*	$890 - 980 *875-965*	$915 – 1,015 *885-980*
Capital Spending	$745 - 815	$370 - 470	$340 - 440

Note: If guidance has changed, previous guidance from 08/03/06 is shown in italics directly below.

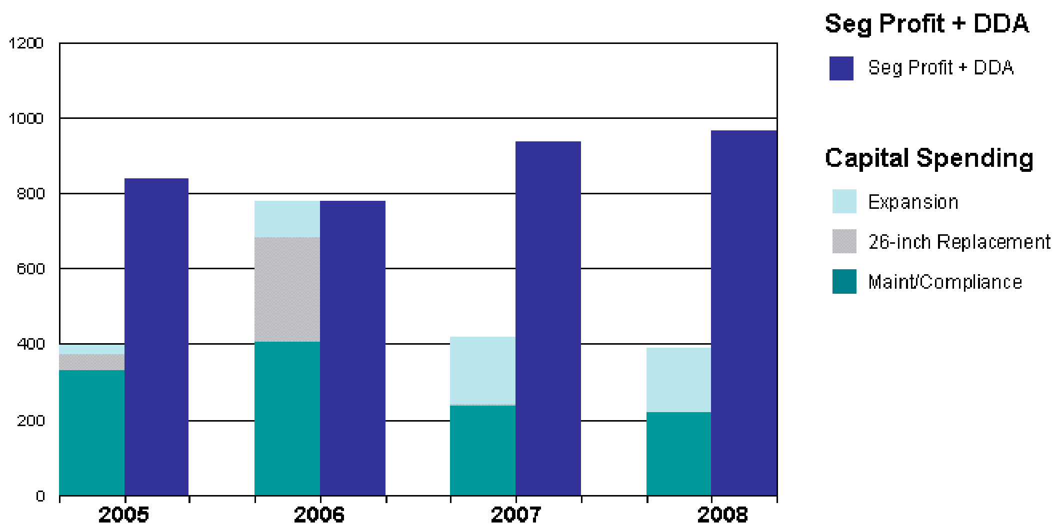
2006-08 Capital Spending Detail

Dollars in millions	2006	2007	2008
Normal Maintenance/Compliance	$375 - 435	$210 - 265	$180 - 260
Northwest 26-inch Replacement	276	2	-
Expansion[1]	95 - 105	160 - 200	160 - 180
Total	$745 - 815	$370 - 470	$340 - 440

[1]**Major Growth Projects (in guidance):**	2006	2007	2008	1st full yr Seg. Profit
Parachute (In Service 1/07)	$50 - 60	$5-10		$9
Leidy to Long Island (In Service11/07)	15 - 20	85 - 100	$1 - 5	20
Potomac (In Service 11/07)	5 - 10	55 - 65	1 - 5	11
Sentinel (In Service Ph1 11/08, Ph2 11/09)	1 - 5	5 - 15	80 - 100	22
Greasewood (In Service 11/08)		0 - 5	20 - 25	5

Note: If guidance has changed, previous guidance from 08/03/06 is shown in italics directly below.
Note: - Sum of ranges may not necessarily match total range

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.

Rate Case Filing

Update	NWP	TGPL
Filing Date	6/30/2006	8/31/2006
Base Period	4/05-3/06	6/05-5/06
Test Period	4/06-12/06	6/06-2/07
Effective Date	1/1/07	3/1/07
Rate Base	$1.5B	$2.95B
Cap Structure (Equity)	55%	62%
Filed Return on Equity	13.6%	13.8%

Power

Segment Profit - Power

Dollars in millions	3rd Quarter 2006	3rd Quarter 2005	YTD 2006	YTD 2005
Segment Profit/(Loss)	($70)	($226)	($172)	($187)
Nonrecurring				
Accrual for regulatory & litigation				
Contingencies/Settlements	4	-	4	13
Contingent obligation adjustments	(13)	-	(13)	5
Expense related to prior periods	-	-	-	7
Recurring segment profit/(loss)	(79)	(226)	(181)	(162)
MTM Adjustment (Recurring)	96	213	268	160
Recurring segment profit/(loss) after MTM Adj.	$17	($13)	$87	($2)

3Q06 to 3Q05 financial highlights

- Increase in hedged cash flows largely due to benefit of structured hedges
- 3Q06 includes ($13) million loss due to lower-of-cost-or market write downs on Storage inventory and ($7) million realized losses on Storage injection hedges. These values are forecasted to be recovered when volumes are withdrawn

2006 YTD to 2005 YTD financial highlights

- Increase in hedged cash flows largely due to benefit of structured hedges
- Decrease in expenses (including SG&A) includes $25 million gain related to sale of certain Enron receivables and $9 million in other non-recurring items
- Includes ($20) million loss due to lower-of-cost-or-market write downs on Storage inventory and ($30) million realized losses on Storage injection hedges. These values are forecasted to be recovered when volumes are withdrawn.
- Includes $51 million gain from liquidation of certain non-core basis positions

Power

2006-08 Guidance

Dollars in millions	2006	2007	2008
Prior Guidance - Segment Loss before MTM Adj	($200) - (150)	($175) - (75)	($155) - (5)
Est. Fwd Impact of 3Q06 MTM Earnings and other portolio adjustments	(40)	100	5
New Guidance - Segment Loss before MTM Adj	($240) - (190)	($75) - 25	($150) - $0
Estimated MTM Adjustments	315 *275*	125 *225*	200 *205*
Segment Profit after MTM Adj	75 - 125	50 - 150	50 - 200
Recurring Segment Profit after MTM Adj	**$75 - 125**	**$50 - 150**	**$50 - 200**
Capital Expenditures	-	-	-

Note: If guidance has changed, previous guidance from 8/03/06 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	($145)	($27)	($172)
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	11		11
Add Realized Gains from MTM Previously Recognized	257		257
Segment Profit/(Loss) After MTM Adjustments	123	(27)	96
Total Working Capital Change[1,2&3]		(198)	(198)
Power Segment CFFO	**$123**	**($225)**	**($102)**

[1]Significant amount of Working Capital used was returned to one counterparty 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*	3Q06A	3Q06F	QTD Variance	YTD06A	YTD06F	YTD Variance	2006A+F
Tolling Demand Payment Obligations	($128)	($127)	(1)	($314)	($312)	(2)	($400)
Hedged Cash Flows [2]	166 [1]	187	(57)	452 [1]	462	(69)	566
Merchant Cash Flows [3]		38			59		18
SG&A and Other [4]	(10)	(21)	11	(29)	(63)	34	(67)
Total Power Portfolio Cash Flows	**$28**	**$77**	**($49)**	**$109**	**$146**	**(37)**	**$117**
Working Capital & Other [5]	122	n/a		(211)	n/a		n/a
Estimated Power Segment Cash Flows	$150			($102)			

[1] Q306 Actual cash flows are realized from a combination of Hedged Cash Flows and Merchant Cash Flows and other risk management and trading activities. Q306 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 primarily reflect the tolling (spread option) cash flows which have not been hedged.

[4] YTD SG&A includes $25 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. Current year Actuals include cash flows from the NG portfolio (including storage related losses offset by the monetization of forward positions), however future periods do not include forecasted NG portfolio cash flows.

Note: Q306 Forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

3Q06 Financial Statement Changes for Derivatives

During 3Q06, 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]	$116	$132	($10)	($6)
Change in E&P Hedge Values	291	242	6	
- Prior MTM Realized (Ineffectiveness)				(7)
- OCI Realized				50
Change in Midstream Hedge Values	26	12		
- Prior MTM Realized			(0)	
- OCI Realized				14
Change in Power Hedge Values	(201)	(122)	(16)	
- Prior MTM Realized				(80)
- OCI Realized				17

- The net change in Derivative Assets and Liabilities for E&P was positive reflecting the 3Q06 decrease in gas prices against a short derivative position
- The net change in Derivative Assets and Liabilities for Midstream was positive reflecting the 3Q06 price decrease on crude and NGL's against a short derivative position
- The net change in Derivative Assets and Liabilities for Power was negative, reflecting the 3Q06 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.

Power

West Undiscounted Cash Flows

Dollars in millions

West Power Portfolio Estimated as of 9/30/06	Q306A	Q306F	QTD Variance	2006F+A
Tolling Demand Payment Obligations	($39)	($38)	($1)	($154)
Hedged Cash Flows [2]	119 [1]	138	(19)	440
Merchant Cash Flows [3]				8
Total Cash Flows	$80	$100	($20)	$294
Capacity Available (in MW)				3,805
Total Capacity Sold				2,720
Remaining Available (in MW) after all hedges				1,085

[1] Q306 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 primarily primarily reflect the tolling (spread option) cash flows which have not been hedged.

Note: Q306 Forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Power

Mid-Con Undiscounted Cash Flows

Dollars in millions

Mid-Continent Power Portfolio *Estimated as of 9/30/06*	Q306A	Q306F	QTD Variance	2006F+A
Tolling Demand Payment Obligations	($41)	($41)	$0	($88)
Hedged Cash Flows [2]	20 [1]	20	0	34
Merchant Cash Flows [3]				5
Total Cash Flows	($21)	($21)	$0	($49)
Capacity Available (in MW)				1,303
Total Capacity Sold				399
Remaining Available (in MW) after all hedges				904

[1] Q306 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 primarily reflect the tolling (spread option) cash flows which have not been hedged.

Note: Q306 Forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

East Undiscounted Cash Flows

Dollars in millions

East Power Portfolio Estimated as of 9/30/06	**Q306A**	**Q306F**	**QTD Variance**	**2006F+A**
Tolling Demand Payment Obligations	($48)	($48)	$0	($158)
Hedged Cash Flows[2]	28[1]	67	(39)	91
Merchant Cash Flows[3]				5
Total Cash Flows	($20)	$19	($39)	($62)
Capacity Available (in MW)				2,280
Total Capacity Sold				1,559
Remaining Available (in MW) after all hedges				721

[1] Q306 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 primarily reflect the tolling (spread option) cash flows which have not been hedged.

Note: Q306 Forecast estimated as of 12/31/05. Variances between regional Cash Flow slides and total Cash Flow Analysis slide may be due to rounding.

Enterprise Risk Management

WMB Collateral Outstanding

Dollars in millions	E&P	Midstream	Power	Corp./ Other	Total
	As of 9/30/06				
Margins & Ad. Assur.	$41	$0	$9	$0	$50
Prepayments	0	0	5	0	5
Subtotal	41	0	14	0	55
Letters of Credit	448	131	382	25	986
Total as of 9/30/06	489	131	396	25	1,041
Total as of 12/31/05	746	243	343	91	1,423
Change	($257)	($112)	$53	($66)	($382)

WMB Collateral Sensitivity

Dollars in millions

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

Days	9/29/2006	6/30/2006	3/31/2006	12/30/2005
30	($155)	($246)	($223)	($325)
180	($459)	($580)	($769)	($559)
360	($471)	($489)	($626)	($567)

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

Enterprise Risk Management

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	$(1)-$1 MM	$2-$4 MM
2007	$5-$8 MM	$2-$4 MM	$17-$19 MM
2008	$13-$15 MM	$5-$8 MM	$18-$21 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).

Consolidated

Consolidated

Liquidity at September 30, 2006

Dollars in millions

Cash and cash equivalents		$ 1,075
Other current securities		160
Less:		
Subsidiary and Int'l cash & cash equivalents	$ 368	
Customer margin deposits payable	77	(445)
Available unrestricted cash		790
Available revolver capacity		1,712
Total Liquidity		**$ 2,502**

Consolidated

2006 Cash Information

Dollars in millions	3rd Quarter	YTD
Beginning unrestricted cash	**$ 980**	**$ 1,597**
Cash flow from continuing operations	634	1,308
Debt retirements	(45)	(774)
Proceeds from debt issuance	-	699
Proceeds from sale of limited partnership units	-	225
Capital expenditures	(756)	(1,759)
Dividends	(54)	(152)
Dividends to minority interests	(11)	(28)
Purchase of auction rate securities	(49)	(376)
Proceeds from sale of auction rate securities	298	320
Other-net	77	15
Change in cash and cash equivalents	$ 94	$ (522)
Ending unrestricted cash at 9/30/06		**$ 1,075**
Restricted cash at 09/30/06 (not included above)		$ 120

Consolidated

Debt Balance[1]

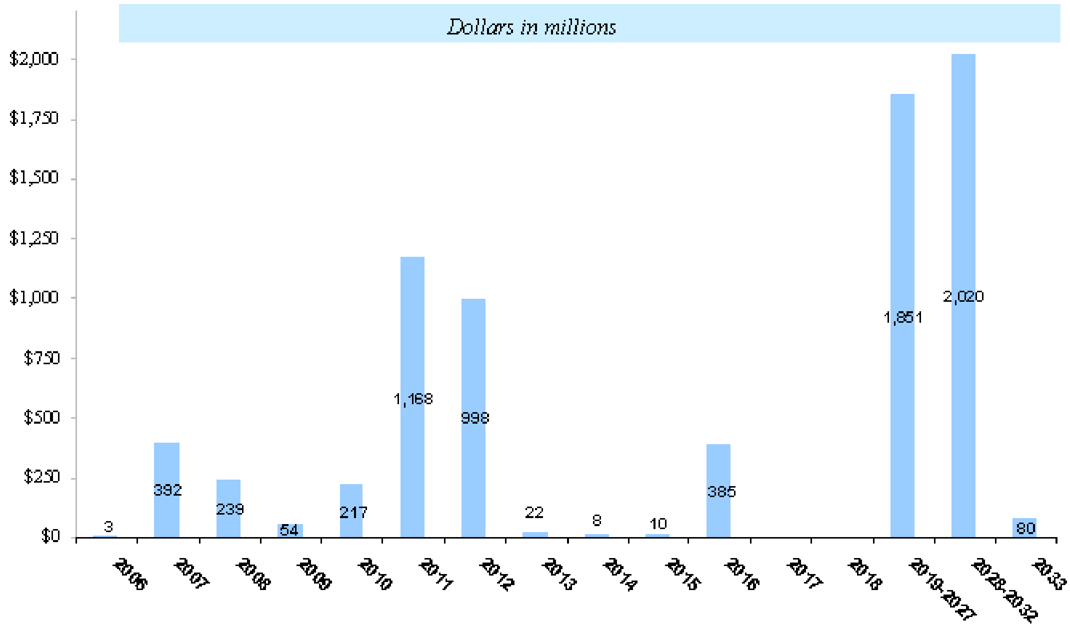
Dollars in millions

		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%**
Scheduled Debt Retirements & Amortization	(45)	
Debt Balance @ 9/30/06	**$7,418**	**7.7%**
Fixed Rate Debt @ 09/30/06	**$7,268**	**7.7%**
Variable Rate Debt @ 09/30/06	**$150**	**6.5%**

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

Consolidated

Debt Amortization – As of 9/30/2006



Consolidated

EPS Metrics

2006	1Q	2Q	3Q	4Q	Total
Diluted EPS from Cont. Ops.	$0.22	($.11)	$0.19	-	$0.29
Recurring EPS	0.23	0.19	0.19	-	0.60
Recurring EPS after MTM Adj.	**0.26**	**0.33**	**0.28**	-	**0.87**
Average Shares (MM)	607	596	609	-	608

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

Consolidated

2006 Interest Expense Forecast Guidance

Dollars in millions	**2006**
Interest on Long-Term Debt	$570 - $580
Amortization Discount/Premium and other Debt Expense	25 - 30
Credit Facilities: (incl. Commitment Fees plus LC Usage)	30 - 40
Interest on other Liabilities	45 - 55
Interest Expense	$670 - $705
Less: Capitalized Interest	(10) - (15)
Net Interest Expense Guidance	**$660 - $690**

2006 Effective Tax Rates

	2006							
	First Quarter		Second Quarter		Third Quarter		Year-to-Date	
Statutory Rate	77	35%	(22)	35%	73	35%	128	35%
State	10	5%	(1)	1%	14	6%	23	6%
Foreign	0	0%	7	-10%	7	3%	14	4%
Nondeductible Expenses *(Shareholder Litigation/Convertible Debentures)*	0	0%	18	-28%	0	0%	18	5%
Other	1	0%	(1)	1%	6	3%	6	2%
Tax Provision/(Benefit)	88	40%	1	-1%	100	47%	189	52%

	2006	2007	2008
Effective Tax Rate Guidance	**39%**	**39%**	**39%**
Cash Tax Rate Guidance	**10-15%**	**5-10%**	**9-14%**

Note 1: Additional income tax expense of $35-45 million in 2006, $10-15 in 2007 and $5-10 million in 2008 is also forecast.