UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported): May 12, 2005

The Williams Companies, Inc.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

Item 8.01. Other Events.

Williams wishes to disclose for Regulation FD purposes its slide presentation, furnished herewith as Exhibit 99.1, to be utilized during a public conference call and webcast on the morning of May 12, 2005.

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

Item 9.01. Financial Statements and Exhibits.

(a) None

(b) None

(c) Exhibits

Exhibit 99.1 Copy of Williams’ slide presentation to be utilized during the May 12, 2005, public conference call and webcast.

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

THE WILLIAMS COMPANIES, INC.

Date: May 12, 2005

/s/ Brian K. Shore

Name: Brian K. Shore

Title: Corporate Secretary

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
Exhibit 99.1	Copy of Williams' slide presentation to be utilized during the May 12, 2005, public conference call and webcast.

EXHIBIT 99.1

Williams Business Update

Steve Malcolm, President and CEO

May 12, 2005

Williams

Forward Looking Statements

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

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

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

Oil & Gas Reserves Disclaimer

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

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

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

Power Update

Bill Hobbs, Senior Vice President

May 12, 2005

Williams

Key Points

- Positive CFFO in a shoulder quarter
- CFFO expected to remain positive
- Risk reducing contracts term sales are occurring
- Expect to see improvements
  - Market liquidity
  - Spark spreads
  - Williams credit
- Active E&P drilling program will increase natural gas sales
- Factors impacting guidance
  - Spark spread movement up or down
  - Capacity market timing and value
  - New long-term contracts

Today's Discussion

- Brief overview of natural gas operations
- Discuss executed power sales
- Regional outlook
- Threats to competitive markets
- Q&A

Power

Natural Gas

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Power

Physical Natural Gas

- Average annual requirements
  - 2.5 Bcf/d with peak of 3.0 Bcf/d
    - 60% for Power
      - 30% power-plant supply
      - 70% third-party transactions
    - 40% for Williams' core businesses
- Transportation
  - 2.5 Bcf/d
    - 50% for gas marketing (including power-generation fuel)
    - 50% for Williams' core businesses
- Storage
  - 13 Bcf
    - 50% for gas marketing (including power-generation fuel)
    - 50% for Williams' core businesses

Power

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Power

Types of Sales Around Tolling Deals

From Most Effective to Least Effective

Type of Sale	How It Works
Resale of tolling	Williams buys tolling rights for a certain dollar amount per kilowatt-year and sells similar or "mirror-image" rights to another party for a larger amount per kilowatt-year. Example: CDWR Product D.
Heat-rate sales	Williams sells for a certain dollar amount per kilowatt-year a heat-rate option (a right to energy priced using a heat-rate) and valued at a smaller amount per kilowatt-year.
Full requirements	Williams serves load of an entity, usually at a fixed price, using production from other Williams assets and/or the entity's resources. Examples: EMC and Allegheny Co-op contracts.
Capacity sales	Generation capacity rights, generally sold on a $/kW-yr or $kW-month basis; but markets and definitions vary.
Forward fixed-price sales	Blocks of power (energy) sold on a fixed-price or heat-rate basis. Examples: CDWR A, B, C.

Power

Recent Successes

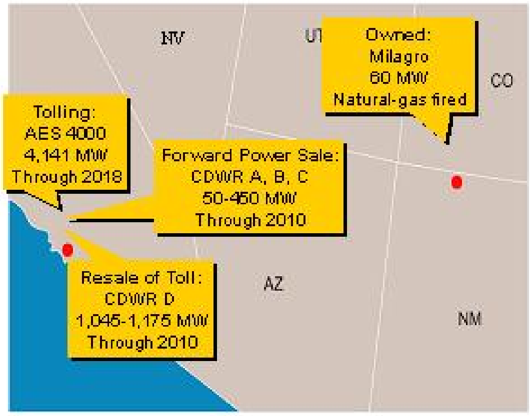
$32 Million EVA to Date on Deals

- West
  - Partial resale of toll, plus gas sale 2006-2008
  - Heat-rate option sale 2008
  - Summer “capacity” sale (contractually-defined rights) 2005
  - Approx. cumulative 1250 MW total over 2005-2008 period
- Mid-Continent
  - 170-MW forward energy sale from CLECO position for June-Sept 2005
- Northeast
  - 100-MW heat-rate option sale to municipality for June 2005-May 2006
- Currently evaluating 10 transactions with terms ranging from 1 to 10 years

Power

Overview of West

- Capacity: 4,141 MW*
- Base term: June 2013
  - 5-year option for either party to extend to 2018
- Annual demand payment:
  - $153 million in 2004-05
  - Escalates 1.0% annually until 2013; flat after 2013



- Variable O&M payment $2.30/MWh in 2005
  - Annual escalator is lesser of 2.5% or CPI
- CDWR sales more than cover demand payments through 2010

** Receiving non-availability payments for 266 MWs that have been retired*

Power

Market Outlook in West

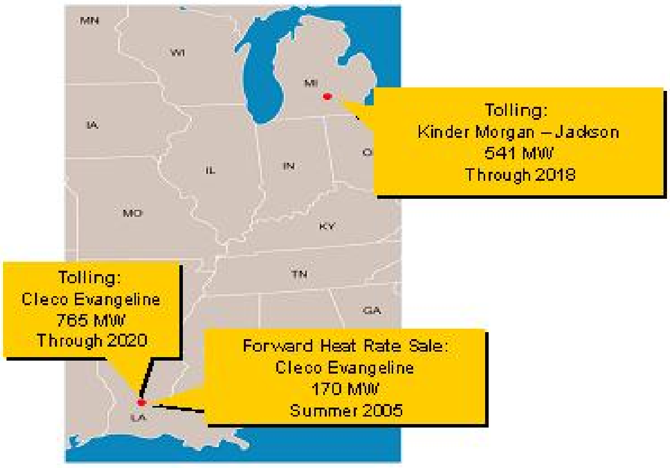
- Market outlook
  - Southern California remains tight on capacity and energy
  - California Energy Commission report shows declining reserve margins in SP-15 through 2009
  - Financial players entering market need physical supply
  - Development of capacity market should enhance Williams' position in later years
  - Schwartzenegger administration promoting competitive market solutions

- Regulatory activity
  - California Public Utilities Commission promoting resource adequacy, competitive procurement and capacity market
  - California Independent System Operator tariff redesign inches forward with regard to development of capacity markets and locational marginal pricing

Power

Overview of Mid-Continent

- Tolling agreements
  - 1,306 MW
  - 7,700 average heat rate
  - Accounts for approximately 22% of approximately $400 million annual demand charges



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Market Outlook in Mid-Continent

- Market outlook
  - Overbuilt in the South with transmission constraints
  - Midwest Independent System Operator (MISO) energy-market implementation and future capacity-market development should increase KM-Jackson value
  - Was active in the Cleco RFP process
  - Industry data suggests supply/demand equilibrium post-2010 for both MISO and SERC-Entergy areas

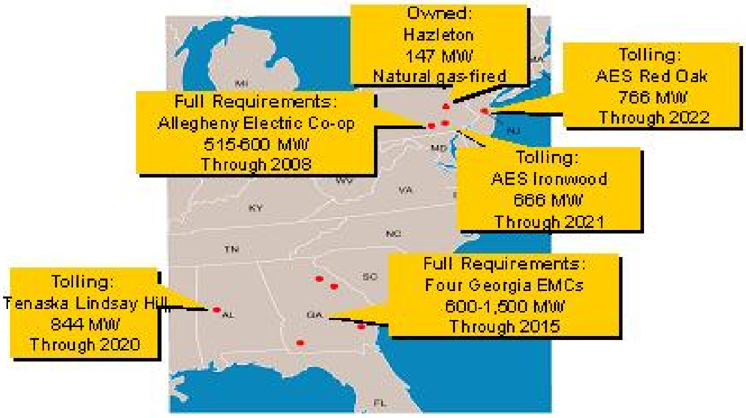
Power

Market Outlook in Mid-Continent

- Regulatory activity - Cleco
  - Entergy introduces independent transmission coordinator (ITC) proposal with Southwest Power Pool as administrator
  - Louisiana commission completes retirement study and identifies significant savings associated with elimination of old plants
- Regulatory activity – KM-Jackson
  - MISO has provided transmission operations services since Feb. 2002
  - Commenced operation in April 2005 of energy markets with economic dispatch and locational marginal pricing
  - Efforts underway to introduce capacity markets and ancillary services by 2006

Overview of the East

- Tolling agreements
  - 2,276 MW; 7,000 average heat rate
  - Accounts for approximately 40% of approximately $400 million annual demand charges
  - Georgia EMCs and Allegheny can be supplied by Tenaska and Ironwood, respectively



Power

Market Outlook in Northeast

- Market outlook
  - Transmission congestion over last year increased Red Oak run time
  - Capacity-market redesign expected to enhance Red Oak, Ironwood values
  - Locational capacity values expected to benefit eastern PJM first
  - Industry data suggests supply/demand equilibrium around 2008

- Regulatory activity
  - PJM expanding westward and southward adds new markets and improves liquidity
  - Market deemed competitive by market monitor
  - Capacity-market redesign encountering near-term obstacles
    - Capacity costs at all-time low
    - Redesign could send stronger, earlier price signals
    - Recognition of locational value of capacity is critical
    - Potential delay of capacity market redesign implementation until 2007

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Potential Threats to Competitive Markets

- Utility self-build despite existing capacity
  - Greater threat to those building new plants
  - Competitive solicitation levels playing field
- Price mitigation continues to undermine competition
  - Utilize uncommitted capacity for reliability needs at below-fair-market value (cost-based rates)
  - Mutes appropriate price signals
  - Provides dis-incentive for new investment
  - Short-term solution to longer term structural imbalance
- Lack of active capacity markets does not reflect appropriate value for assets/location and limits appetite for new investment

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Power

Estimated Total Cash Flows

Undiscounted dollars in millions

Combined Power Portfolio Estimated as of 3/31/05	Q1A	2005A+F	2006F	2007F	2008-2010F	2011-2022F
Tolling Demand Payment Obligations	($89)	($368)	($402)	($406)	($1,233)	($3,868)
Resale of Tolling	$41	$126	$106	$96	$158	$0
Full Requirements	($2)	$3	($7)	$0	$6	$26
Long-term Physical Forward Power Sales	$22	$25	($13)	($1)	$29	$0
OTC Hedges	$34	$146	$205	$66	$107	$58
Estimated Hedged Tolling Revenues	$15	$184	$279	$283	$588	$279
Subtotal	$21	$116	$168	$38	($345)	($3,505)
Estimated Merchant Cash Flows	$0	$79	$28	$156	$873	$5,850
Est. Combined Power Portfolio Cash Flows	$21	$195	$196	$194	$528	$2,345
Est. NG Portfolio Cash Flows	$11	($14)	$1	$5	$70	($63)
SG&A and Other	($26)	($81)	($73)	($75)	($225)	($800)
Subtotal	$6	$100	$124	$124	$373	$1,482
Working Capital and Other	$42	$23	$1	$3	$6	$103
Estimated Cash Flows After SG&A	$48	$123	$125	$127	$379	$1,585
Capacity Available (in MW)		5,149	7,723	7,723	7,723	7,723
Expected Output (in MW)		1,533	2,289	2,530	2,917	3,479
Total Volume Hedged (in MW)		1,451	1,977	1,867	1,172	136
Percentage Volume Hedges		95%	91%	73%	40%	5%

Est Demand Payment Coverage through 2010 - hedged		
Total Estimated Hedged Cash Flows	$	2,386
Total Demand Payments	$	(2,409)
Cost Coverage		0.99

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.
Note: 2005 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.
Note: Est. NG Portfolio Cash Flows represent expected cashflows from NG Storage, Transport and hedges.

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2005-2007 Guidance

Dollars in millions	2005	2006	2007
2/23/05 Segment Profit Guidance	($250) – (150)	($200) – (50)	($100) – 50
1st Quarter 2005 Impact:			
MTM Earnings	221	-	-
Est. Forward Impact of MTM	(32)	(54)	(92)
Total 1st Quarter 2005 Impact	189	(54)	(92)
Change in Segment Profit Guidance	200	(50)	(100)
Revised Segment Profit Guidance	($50) – 50	($250) – (100)	($200) – (50)
MTM Adjustments*	100 *300*	300 *250*	250 *150*
Segment Profit after MTM Adjustments*	50 – 150	50 – 200	50 – 200
		Unchanged	
Cash Flow from Operations*	50 – 150	50 – 200	50 – 200
		Unchanged	
Capital Expenditures	-	-	-

* *If guidance has changed, previous guidance from 2/23/05 is shown in italics directly below*

Q&A

Questions?

Gas Pipeline Update

Phil Wright, Senior Vice President

May 12, 2005

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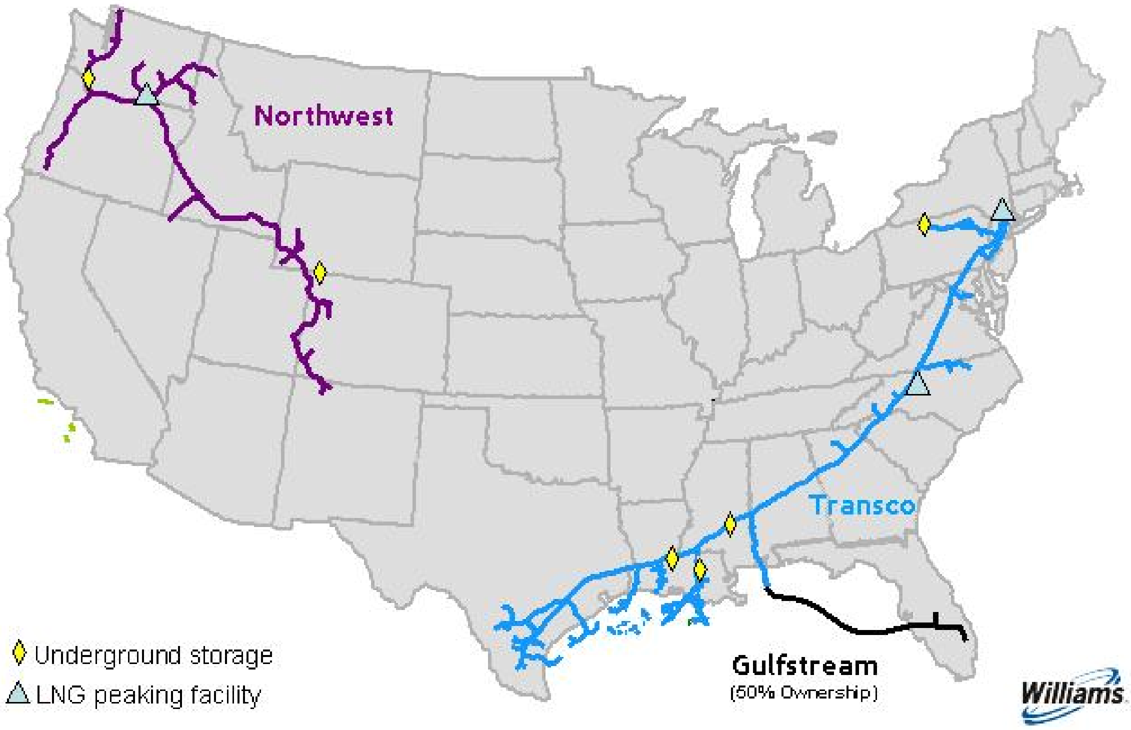
Quality Assets Serving Growth Markets



Strategy Overview

- **Strategic Objective**
  - Maximize utilization of pipeline system capacity
    - Provide high quality, low cost services
    - Maintain access to supplies and markets
- **Customer Value Proposition**
  - Reliable service
  - Low cost

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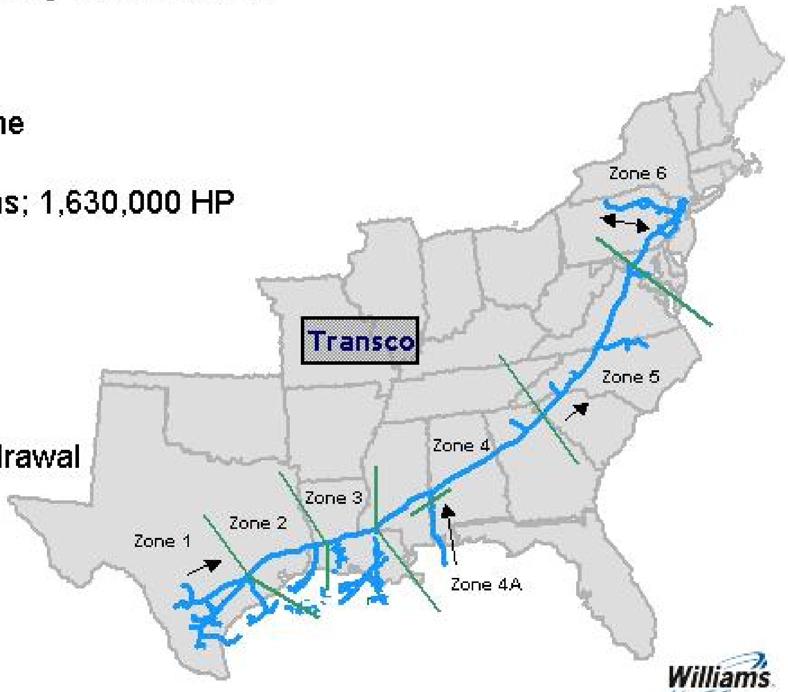
Gas Pipeline

Transco – Premier System Serving the Atlantic Seaboard

- **Peak day design capacity of 8.1 Bcf/d**
- **Assets**
  - 10,500 miles of pipeline
  - 7 storage facilities
  - 44 compressor stations; 1,630,000 HP
  - Rate base $2.7 B
  - Zonal rate structure
- **Seasonal storage**
  - 220 Bcf of capacity
  - 4,870 MMcf/d of withdrawal capability



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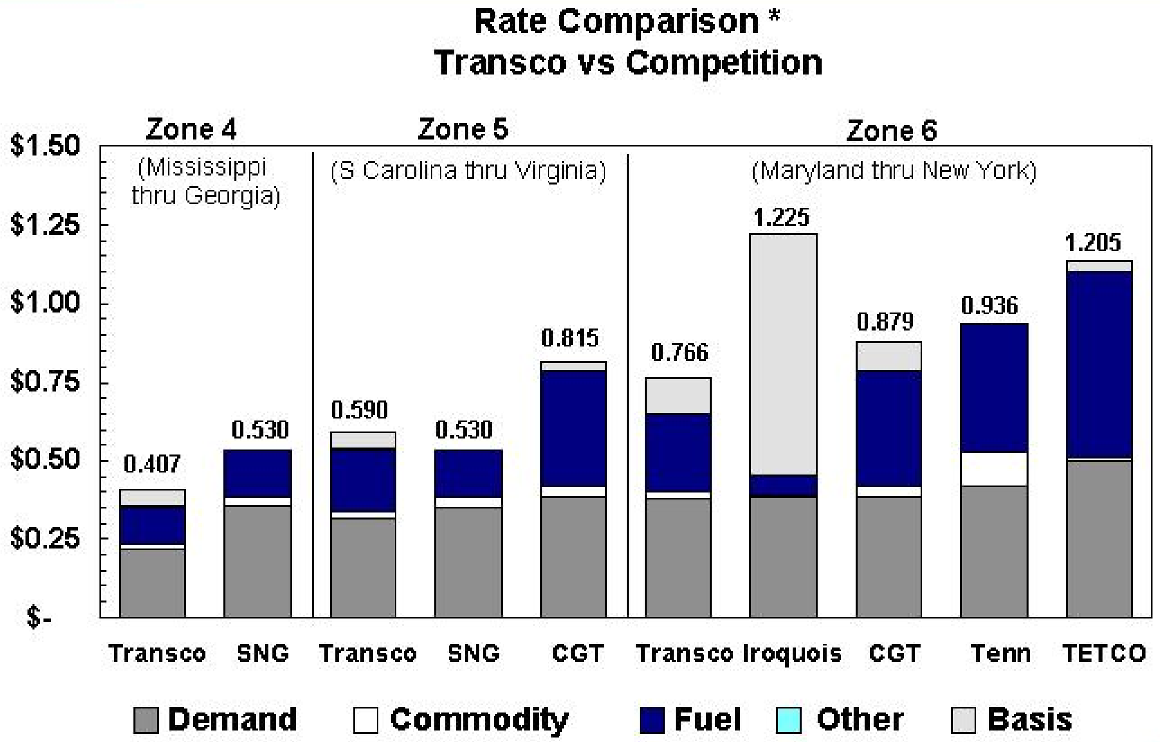
Gas Pipeline

Transco - Rate Comparisons

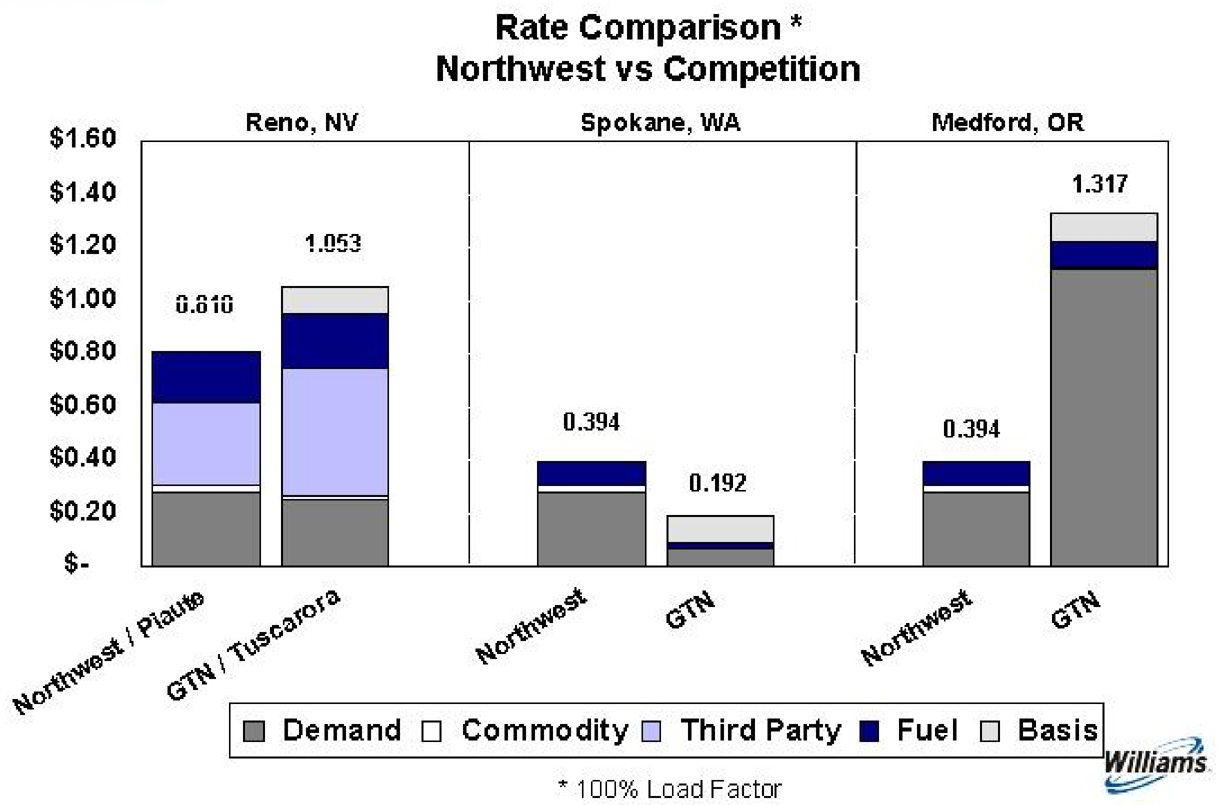


* 100% Load Factor

Northwest – Multiple Supply Sources Serving the Northwest

- **Peak Day design capacity of 3.5 Bcf/d**
- **Assets**
  - 4,100 miles of pipeline
  - 3 storage facilities
  - 42 compressor stations; 350,000 HP
  - Rate base $1.1 B
  - Postage stamp rates
- **Seasonal storage**
  - 12.4 Bcf of capacity
  - 608 MMcf/d of withdrawal capability

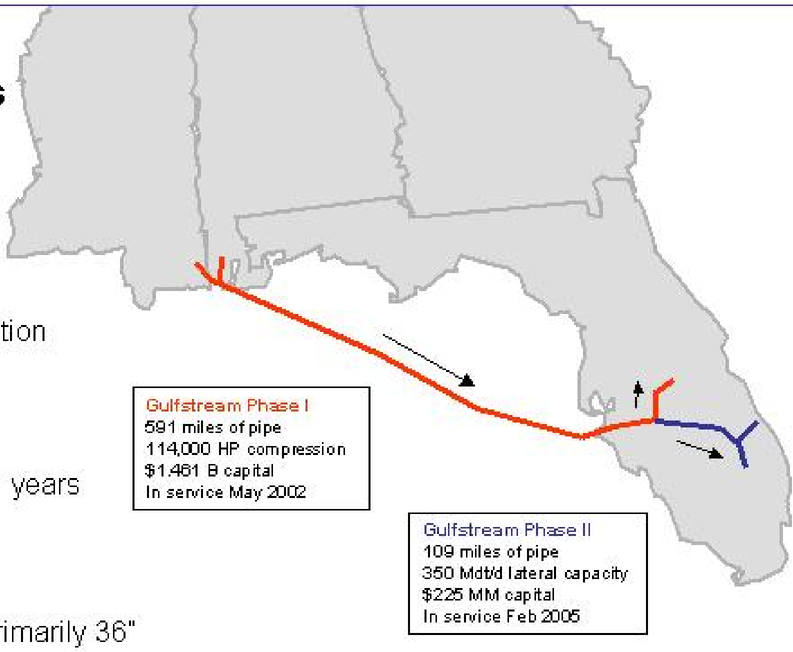
Northwest - Rate Comparisons



Gas Pipeline

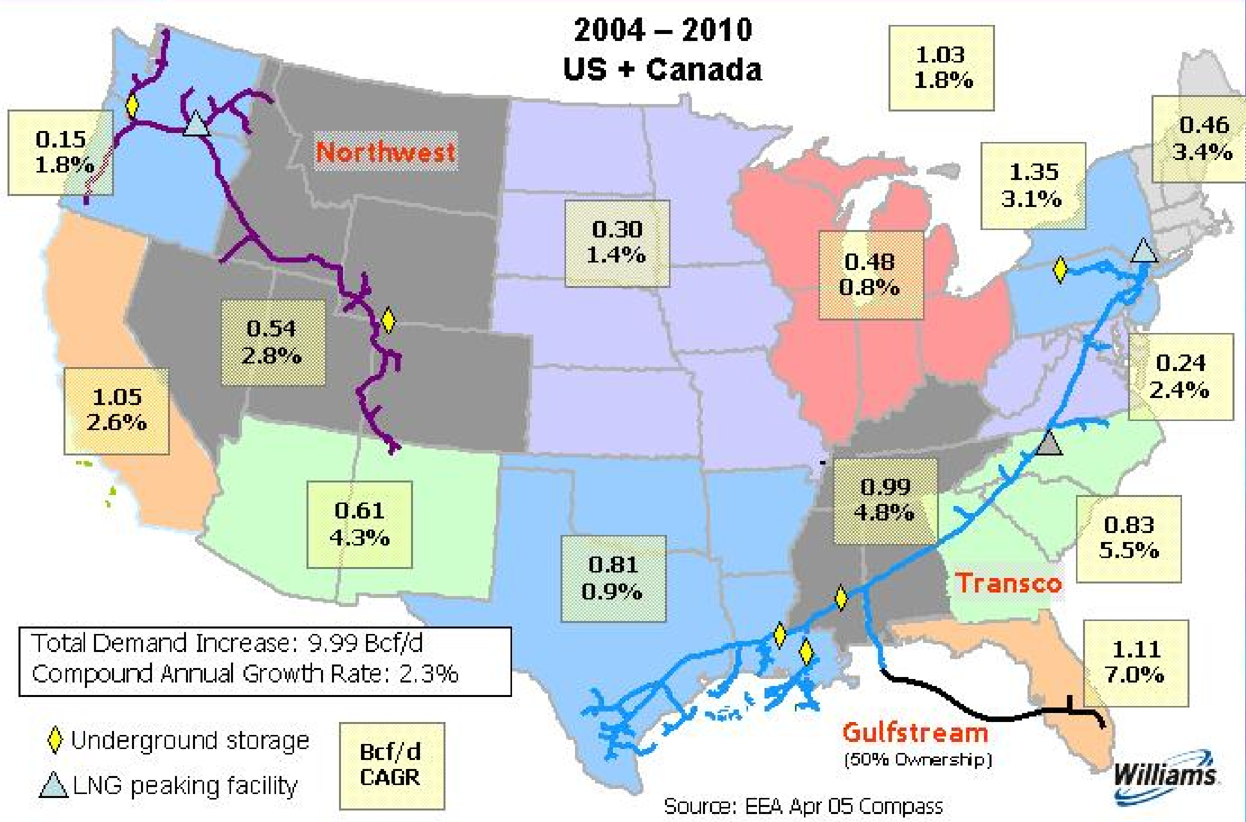
Gulfstream – Pipeline To A Fast Growing Market

- **Large supply sources**
  - Mobile Bay
  - Eastern Louisiana
  - Mississippi
- **High growth**
  - Gas fired power generation
  - Population
- **Long term contracts**
  - Average contract life 20 years
- **Assets**
  - Capacity 1.1 Bcfd
  - 700 miles of pipeline; primarily 36"
  - 1 compressor station; 114,000 HP
  - 1 gas processing plant
  - Rate base $1.4 B



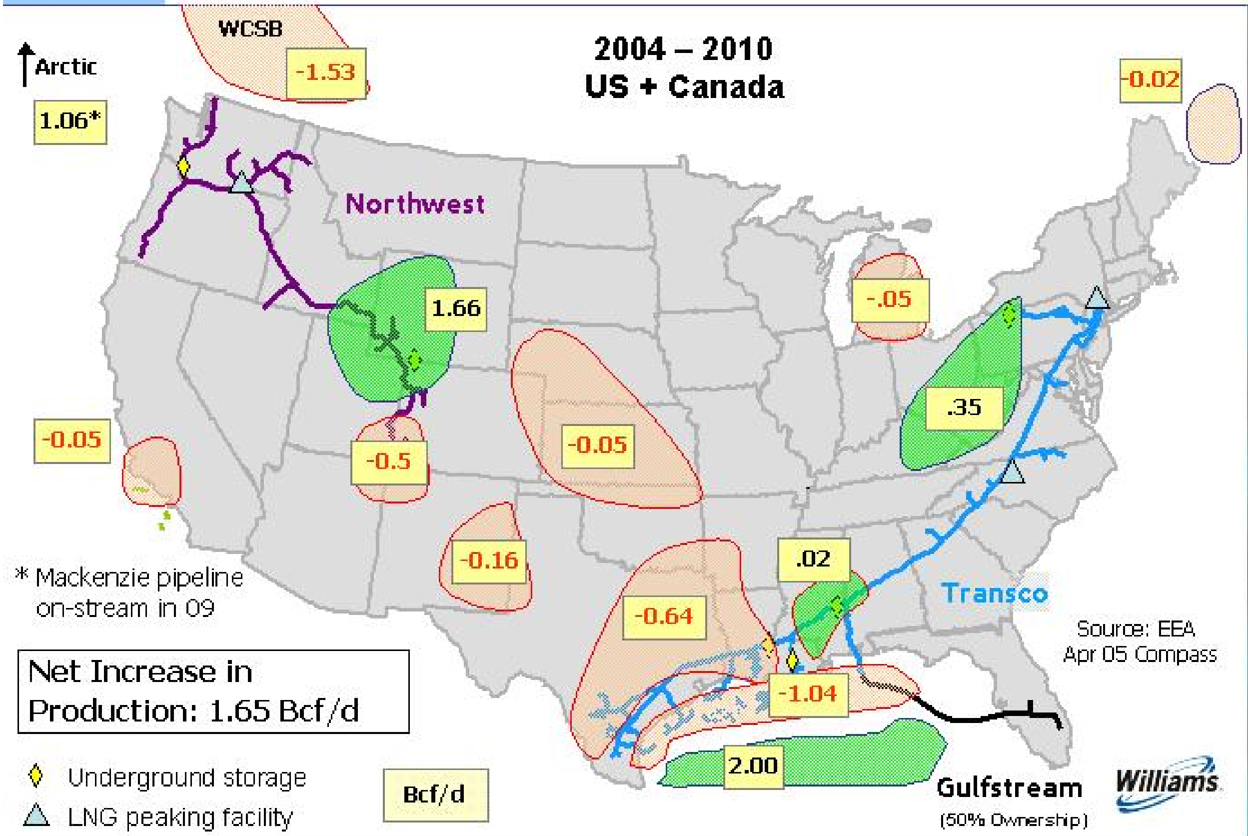
Gas Pipeline

Favorable Demand Outlook



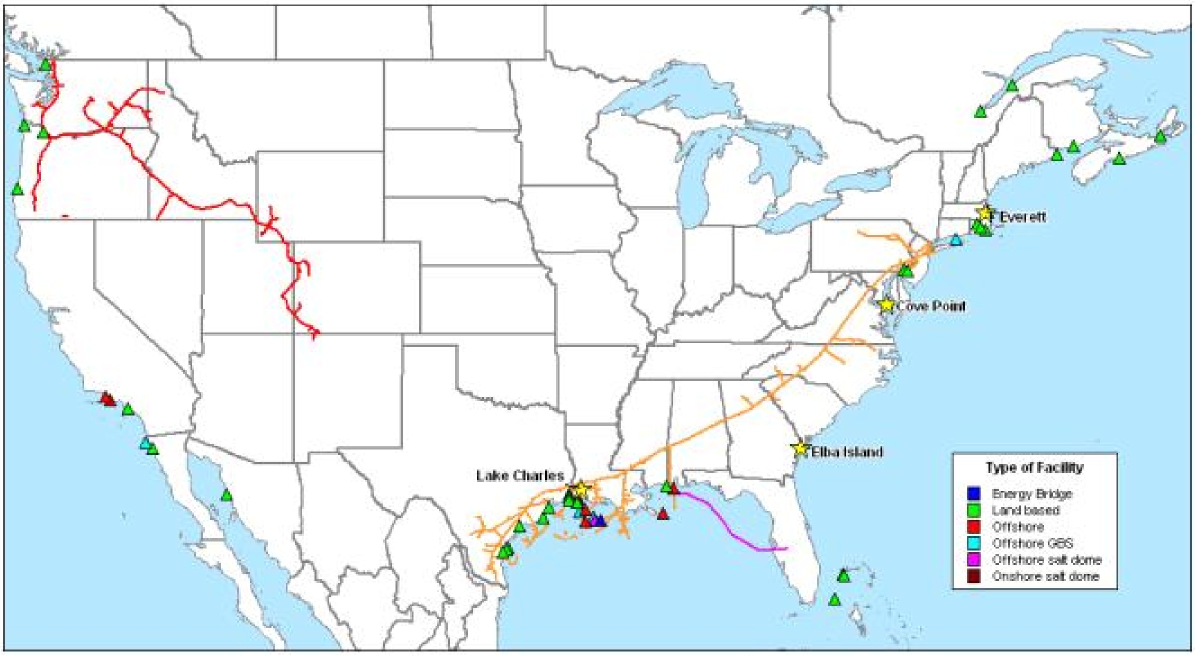
Gas Pipeline

Supply Outlook – Access to Diverse Supplies



Gas Pipeline

Positioned for Proposed & Existing LNG Imports



Net Increase (Bcfd)	
Production:	1.65
LNG + Other:	8.34
Total	9.99

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Gas Pipeline

Accommodating LNG Imports

- **WGP Advantages**
  - Serves markets that are large, diverse, and growing
  - Proximity to LNG terminals
    - Existing Cove Point facility on the east coast
    - Advancing Gulf Coast projects
    - Pacific Northwest proposals
  - Redelivery flexibility
  - Low rates
- **Challenges**
  - Maintaining gas quality
  - Maintaining operational flexibility

Nature of Pipeline Investments

- Utility franchise (FERC regulation)
- Relatively capital intensive with long lived immobile facilities
- Stable and predictable cash flow that provides financial synergies and higher credit ratings

How Pipelines Make Money

- **Provide transportation and storage service under firm and interruptible contracts**
  - Most revenue collected under long term contracts with credit-worthy customers
  - Relatively limited exposure to throughput and basis fluctuations
- **Subject to Cost of Service regulation**
  - Allowed to recover prudently incurred costs
  - Rates include an allowed rate of return

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How Pipelines Make Money – The Mechanics

- Allowed to recover costs through rates based on "Cost of Service"
- Cost of Service

  O&M and A&G Expenses
  + Depreciation Expense
  + Taxes Other Than Income (state, ad valorem)
  + Federal and State Income Taxes
  + Allowed Return

  Cost of Service (revenue)

  - Allowed Return = Rate Base x Rate of Return %

    Rate Base = Net Plant + Working Capital – Deferred Taxes

    Rate of Return % = weighted average cost of debt and equity

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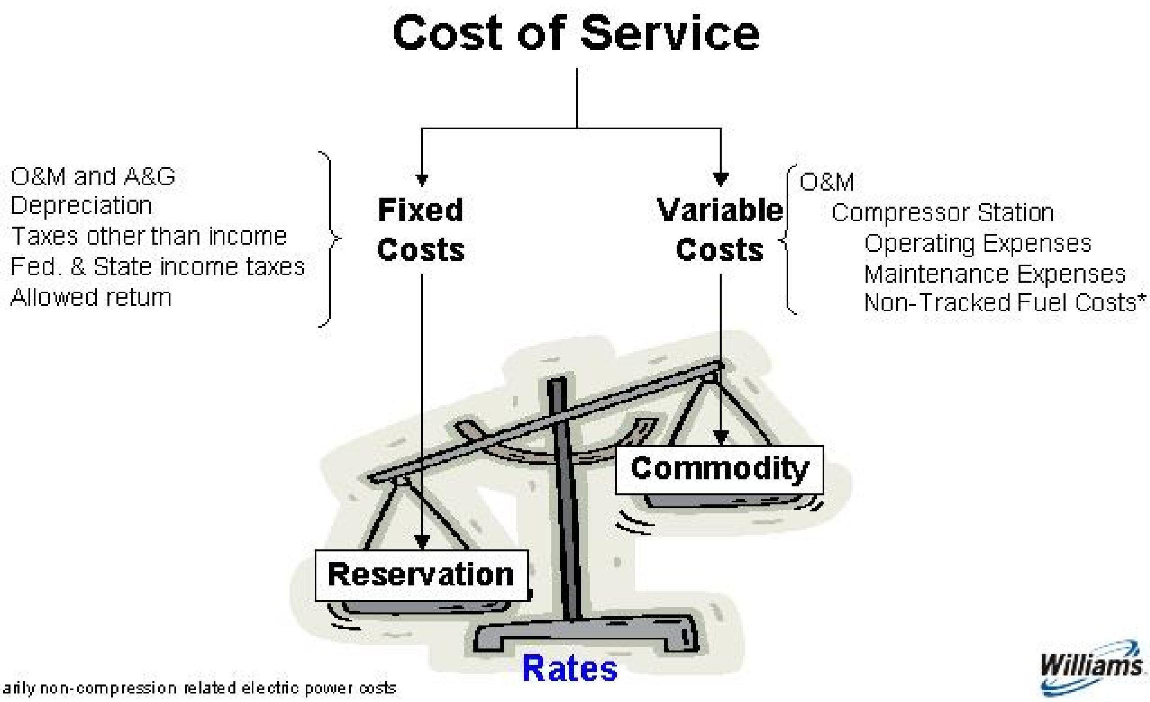
How Pipelines Make Money – The Mechanics

Straight Fixed Variable Rate Design



* Primarily non-compression related electric power costs

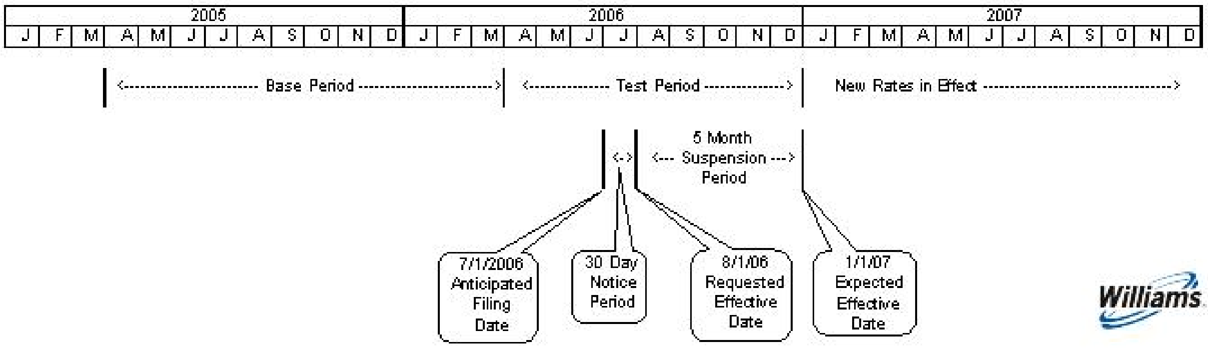
How Pipelines Make Money – The Mechanics

- **FERC must approve rates through a rate case**
  - Customers and other interested parties may intervene
  - Extensive documentation and support is presented in the rate case filing and through the discovery process
  - Issues raised during the rate case are resolved either through litigation or a mutually agreeable settlement
  - Key components include:
    - Capital Investment
    - O&M and Other Expenses
    - Rate of Return %
    - Anticipated Volumes
- **Rate case timeline**
  - Filing Date – 6 months prior to effective date (30 day notice + 5 month suspension)
  - Test Period – 9 months preceding the effective date
  - Base Period – 12 months ending no more than 120 days prior to the filing date

Future Rate Case - Northwest

- **Next anticipated rate case effective Q1 2007**
  - 26-inch Replacement Project the primary driver
- **Last rate case effective March 1997**
- **No requirement to file**

NWPL Docket No. RP06-XX
Key Dates

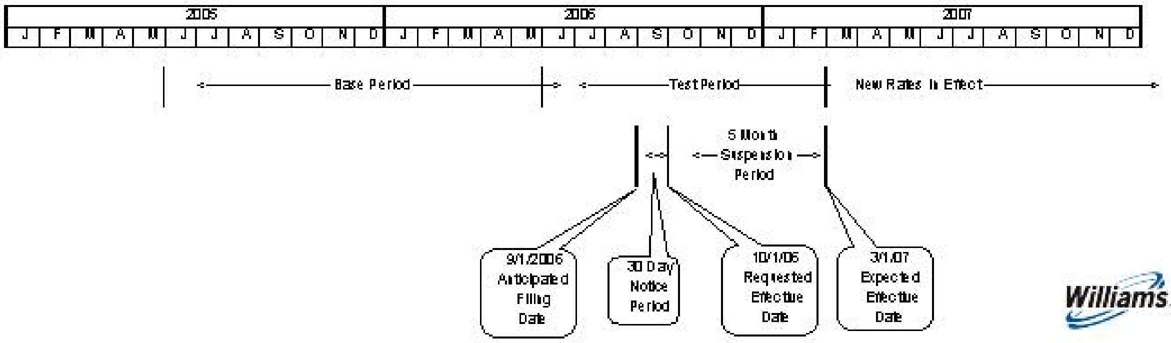


Gas Pipeline

Future Rate Case - Transco

- **Next rate case effective Q1 2007**
  - Driven by Clean Air Act and Pipeline Safety Improvement Act spending
- **Last rate case effective September 2001**
- **Required to file per last settlement**

TGPL Docket No. RP06-XX
Key Dates



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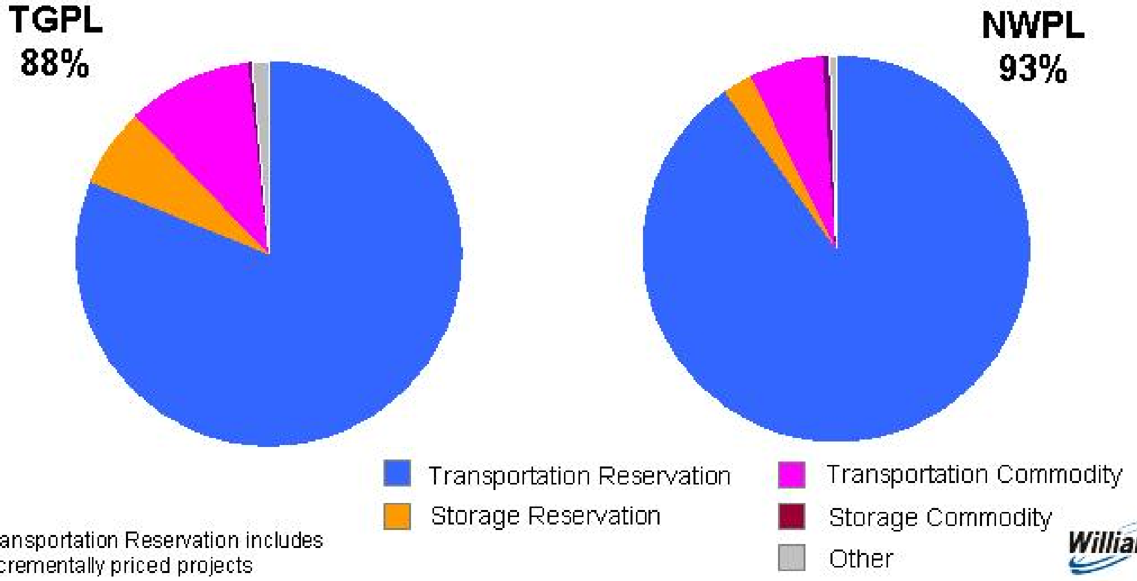
Revenue Breakout

Approximately 90% of 2004 operating revenues were from transportation and storage reservation charges

2004 Revenue



Transportation Reservation includes incrementally priced projects

Top Customers – Large, Long Term, Credit Worthy

TGPL Customer	Credit Rating
PSEG	BBB
KeySpan	A+
AGL Resources	A-
Piedmont	A
Con Ed	A
SCANA	A-
Exelon	A-

NWPL Customer	Credit Rating
Puget Sound	BBB-
N W Natural	A+
Avista Corp	BB+
Cascade Natural Gas	BBB+
Pan Alberta Gas	guarantee
Intermountain Gas	private
Occidental Energy Marketing	guarantee

Gas Pipeline

2005-2007 Guidance

1Q05 Earnings Call

Dollars in millions	2005	2006	2007
Segment Profit [(1)]	$555 - 585 *545 - 585*	$500 - 565 [(2)] *515 - 565*	$565 - 635 [(2)] *575 - 635*
Annual DD&A	280 - 290	290 - 300	300 - 310
Segment Profit + DDA	$835 - 875 *825 - 875*	$790 - 865 *805 - 865*	$865 - 945 *875 - 945*
Capital Spending	$370 - 420	$475 - 550	$250 - 325

1 *Reflects termination of Gray's Harbor contract in 1Q05*

2 *Assumes 1/1/06 refinancing of $250 million of debt and additional financing of $350 million for Gulfstream.*

Note: If guidance has changed, previous guidance from 2/23/05 is shown in italics directly below

Williams

Gas Pipeline

Cornerstone of the Williams Portfolio

- **Stable and predictable cash flow**
- **Future investment opportunities**
- **Strong and diverse markets with growth**
- **Strong and diverse supply**
- **Premier pipeline franchises**
- **Both Transco and Northwest received top ranking in the Mastio & Co. customer survey**
  - Transco ranked #1 in the Northeast Region in customer satisfaction among 16 mega pipelines
  - Northwest ranked #1 in Western Region in customer satisfaction for the second year in a row

Q&A

Questions?

Exploration & Production Update

Ralph Hill, Senior Vice President

May 12, 2005

Williams

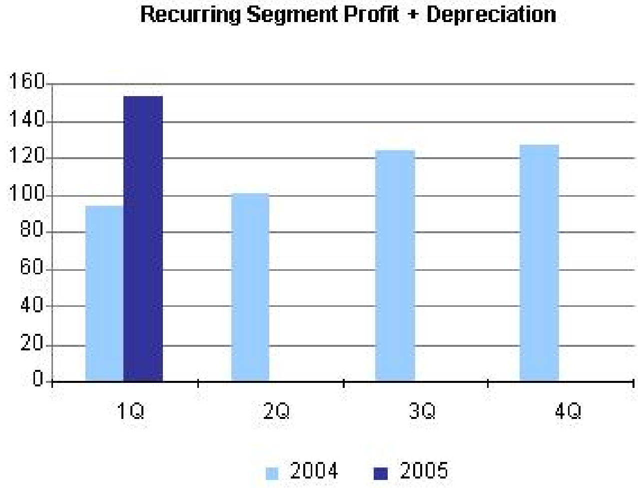
Strategy

- Grow our premier position in select regions, utilizing our expertise in basin-centered tight sands/shale and coal bed methane (CBM)
  - Strategy remains rapid development of our significant drilling inventory
  - Maintain top quartile position in efficiency and cost measures
  - Be the operator of choice for landowners or producers seeking partners
  - Leverage technological advancements in drilling, completion and operational activities
  - Expand core areas through bolt-on acquisitions and farm-ins
  - Add new core growth areas through strategic acquisitions

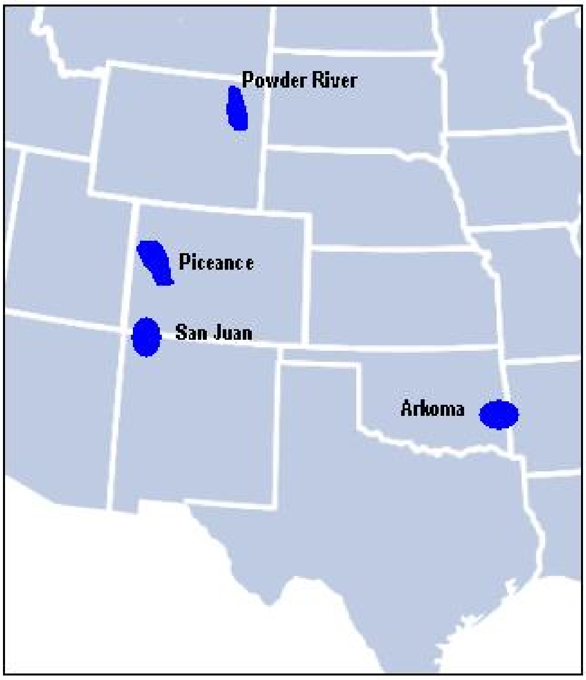
Exploration & Production

2005 Accomplishments

- 1Q 2005 Segment Profit over 100% higher than 1Q04
- 1Q 2005 production up 22%, 112 MMcfed since 1Q04
- Piceance production up 59% since 1Q04
- Piceance higher activity, 10 new H&P rigs contracted
- Additional Piceance 10-acre spacing approved
- Trail Ridge/Ryan Gulch additional drilling this year
- Big George volumes continue to increase
- San Juan production up 13% since 1Q04
- Arkoma Caney shale position expanded



Unique Drilling Portfolio

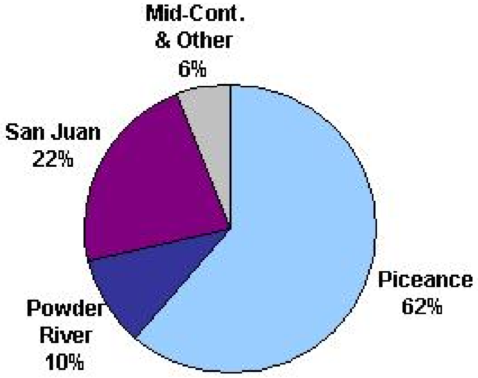


- North American unconventional natural gas production
- Focused portfolio of large well-defined resources
- Repeatability of results, very high success rate
- Long-term, low-risk, high-return drilling portfolio
- Strong organic production growth
- R/P ratio of 15.6 years
- Drilling approx. 1,400 wells/yr

Exploration & Production

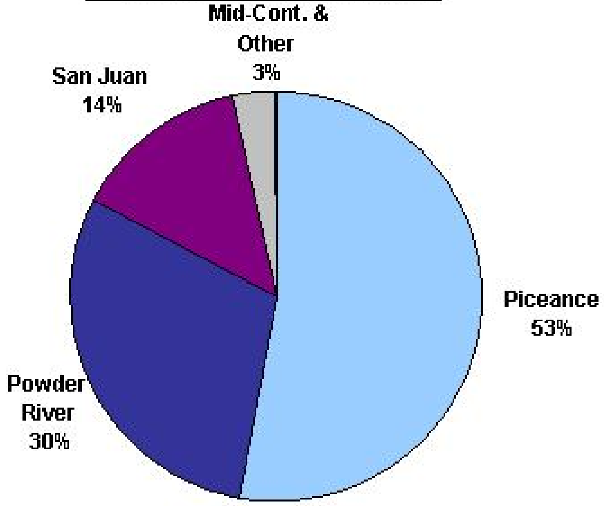
Domestic Reserves

2004 Year End Proved Reserves



TOTAL: 3.0 Tcf Proved*

Proved, Probable & Possible Reserves



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

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

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

Exploration & Production

Domestic Reserves

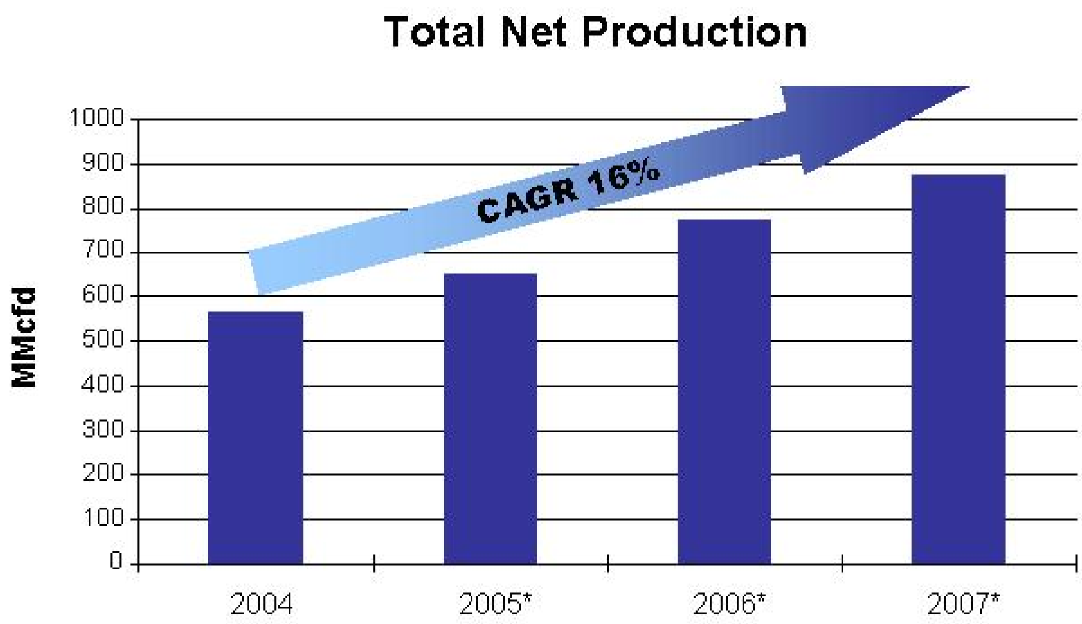
- Domestic proved reserves up 10.5% to 3.0 Tcfe
- Total proved reserves 3.2 Tcfe
- 248% reserves replacement
- 99% success rate
- Moved 451 Bcfe to proven

Transfers of Probable to Proved (Bcf)

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

Exploration & Production

Production Growth



* Assumes Midpoint of Guidance

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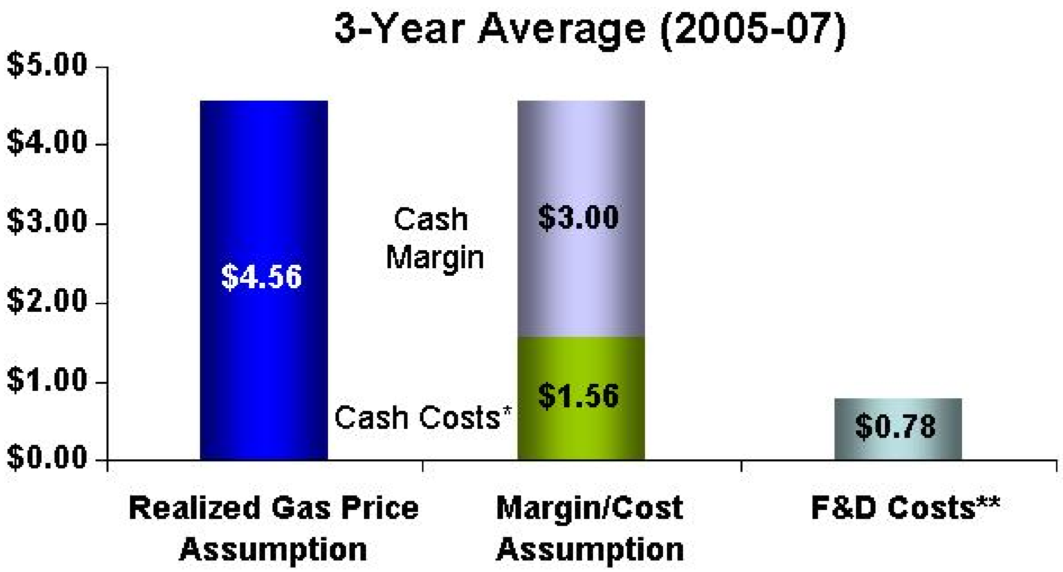
Exploration & Production

Cash Margin Analysis



Reflective of core basins

* *Includes LOE, G&A, taxes and gathering*

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

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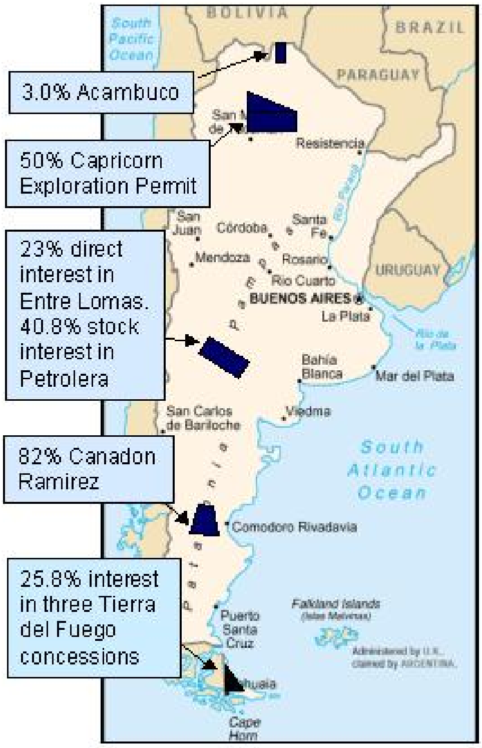
Basin Summaries

International E&P

- Proved reserves total 37 MMboe (222 Bcfe)
- 5,700 Bbl/d net oil & liquids production
- 17 MMcf/d net gas production
- 69% ownership in Apco Argentina
- 10% ownership in La Concepcion
- In-fill, field extension drilling
- Exploration upside
- High investment returns, fast cash cycle
- Complements domestic long life reserves strategy
- Provides perspective on international opportunities



Arkoma Basin – Horizontal Expertise

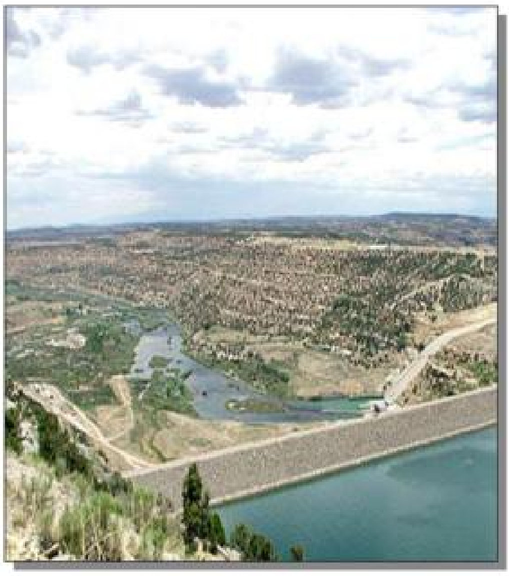
- CBM and emerging shale activity
- Williams' Basin Statistics:
  - Proved reserves total 121Bcfe
  - ~20 MMcf/d net production growing 10-15% annually
  - Leasehold approx. 118,000 net acres
  - ~325 total wells, 70% operated
  - Have drilled 162 extended reach horizontal lateral wells
  - 2004 drilling success rate of 90%
- 50 – 60 Operated wells drilled per year
- Caney and Woodford Shale potential offers growth opportunities
- Caney Shale Exposure
  - ~68,000 net acres
  - Drilling 3rd operated well
  - Gas saturated column offers conventional upside
  - Application of horizontal technology

Williams

Exploration & Production

San Juan Basin - Foundation

- Conventional and coal bed methane production
- Long life / slow decline wells
- Williams' proved reserves total 671 Bcfe
- ~150 MMcfe/d of net production growing 3-5% annually next two years
- 13% growth year over year
- Low risk in-fill drilling
- 40-60 operated wells drilled per year
- 200 – 250 undeveloped locations
- Attractive returns with near 100% success rates
- Leasehold 121,200 net acres
- ~680 operated and 1,900+ joint interest wells
- Good pipeline infrastructure/market access



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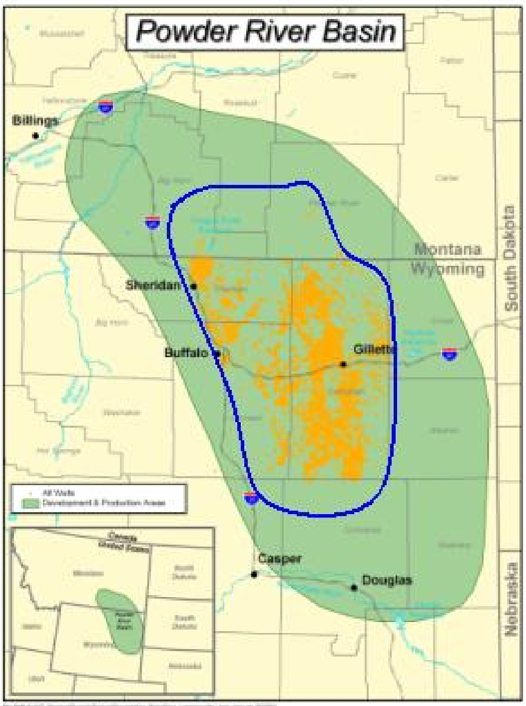
Exploration & Production

Powder River Basin Overview



- Current CBM production 891 MMcfe/d*
- 39 Tcf Gas-In-Place**
- 18,400 wells drilled to date*
- 33,600 additional potential locations in WY
- 15,000 potential locations in MT
- First significant CBM production 1995

* WOGCC Data January 2005

** USGS Estimate 2002

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Exploration & Production

Powder River Basin – Ready to Roll Again

- High potential, low-risk development play, low cost wells
- Williams' proved reserves total 299 Bcfe
- Leasehold 1,021,400 gross/466,000 net acres
- ~4,810 total wells, 53% operated
- 2004 drilling success rate of 99%
- ~110 MMcfe/d net production
- ~9,000 drilling locations; 46% operated

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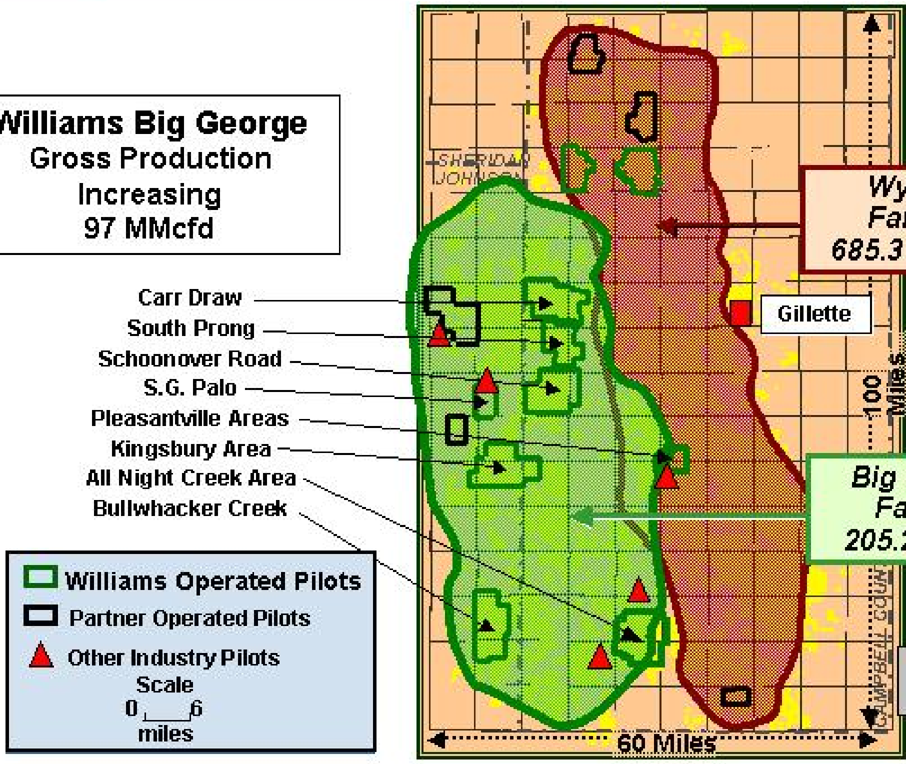
Powder River Basin
Big George & Wyodak Coal Fairways

Williams Big George
Gross Production
Increasing
97 MMcfd



•WOGCC Data Jan 2005
•** April 2005

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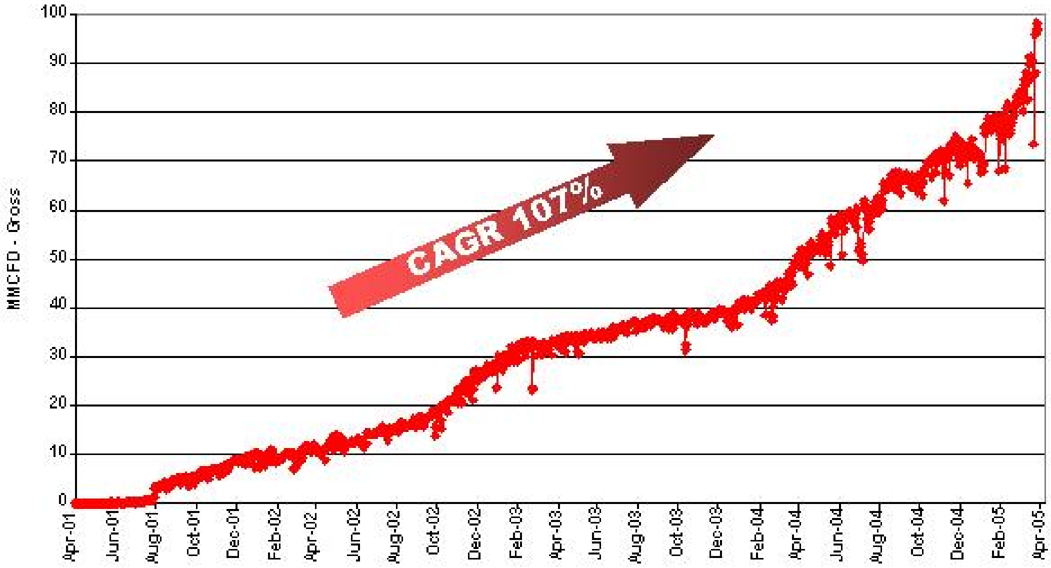
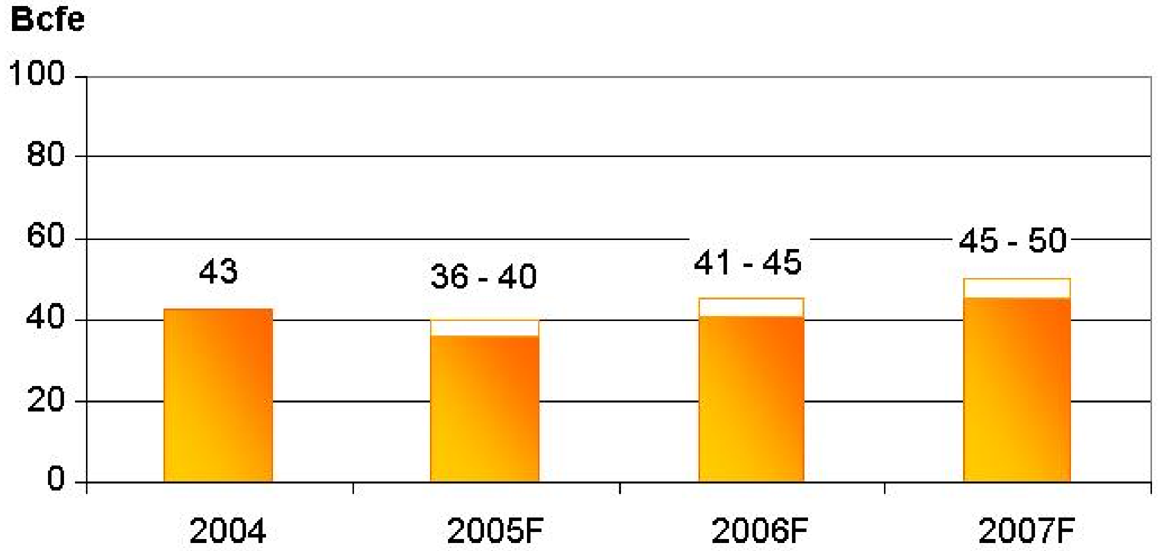
Powder River Basin
Williams Operated Big George Daily Production



Exploration & Production

Powder River Basin
Net Production Forecast



	2004	2005F	2006F	2007F
Wells Spud	705	700 - 775	770 - 775	770 - 775
MMcfe/d	118	100 - 111	111 - 123	136 - 151

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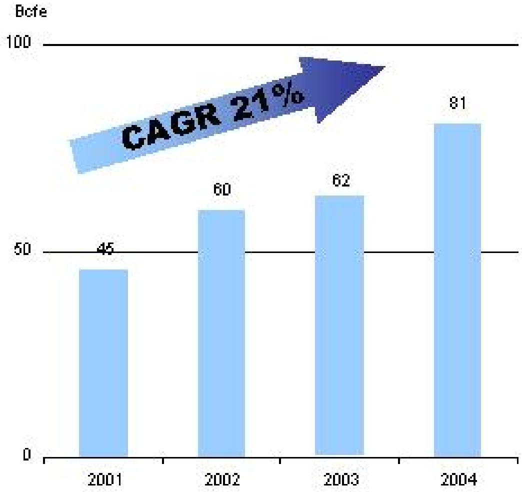
Exploration & Production

Piceance Basin – Cornerstone Asset

Williams

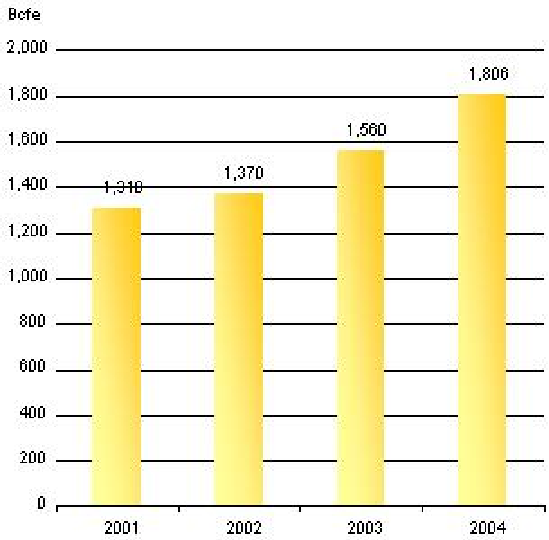
Piceance Basin
Record of Results Delivery

Annual Net Production

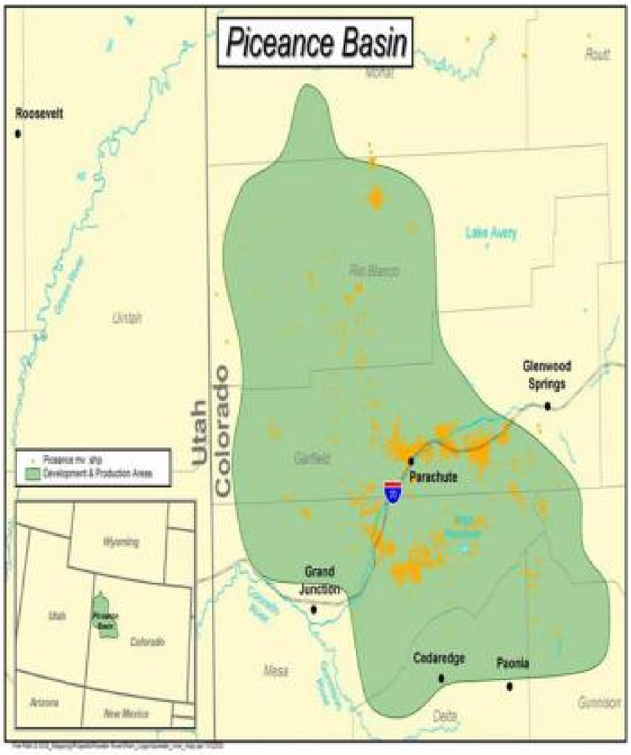


Wells Spud	109	124	76	243
MMcfe/d	123	164	170	222

Reserves



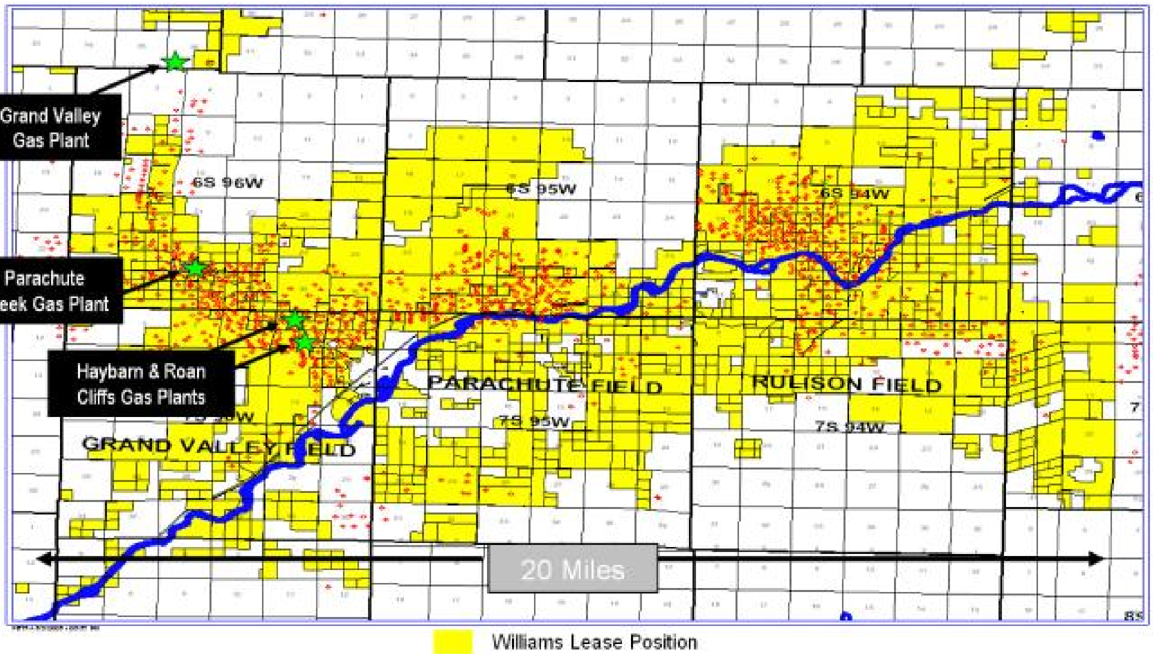
Piceance Basin
Overview



- Production ~900 MMcfe/d
- ~1,400,000 acres
- Gas-in-place estimates over 100 Tcf
- ~2,000 Mesaverde active wells
- ~3,000 additional locations on Williams valley acreage alone

Exploration & Production

Piceance Basin
Area Map



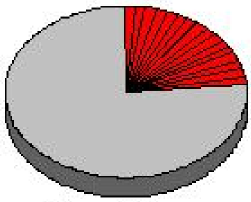
- 20th Year of Development 134,000 Net Acres
- One of the largest natural gas producers in Piceance Basin
- >350 MMcfd Gross Operated Production
- Operate 1100+ wells, 98% WI
- Operate 250+ miles of gathering and 4 gas plants
- Access to 5 major interstate / intrastate pipelines
- Currently 13 drilling rigs operating

Exploration & Production

Piceance Basin
Gas Recovery Estimates vs. Well Density

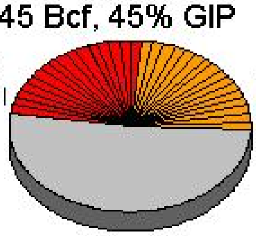
Typical Piceance Valley Section
100 Bcf Gas in Place / Square Mile

40-Acre Development
16 Wells / Section
22 Bcf, 22% GIP



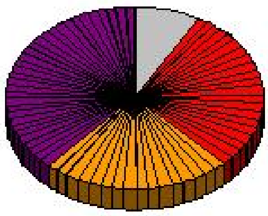
Remaining
Gas in Place
78 Bcf

20-Acre Development
32 Wells / Section
45 Bcf, 45% GIP



Remaining
Gas in Place
55 Bcf

10-Acre Development
64 Wells / Section
Total Recoverable Gas
90 Bcf, 90% GIP



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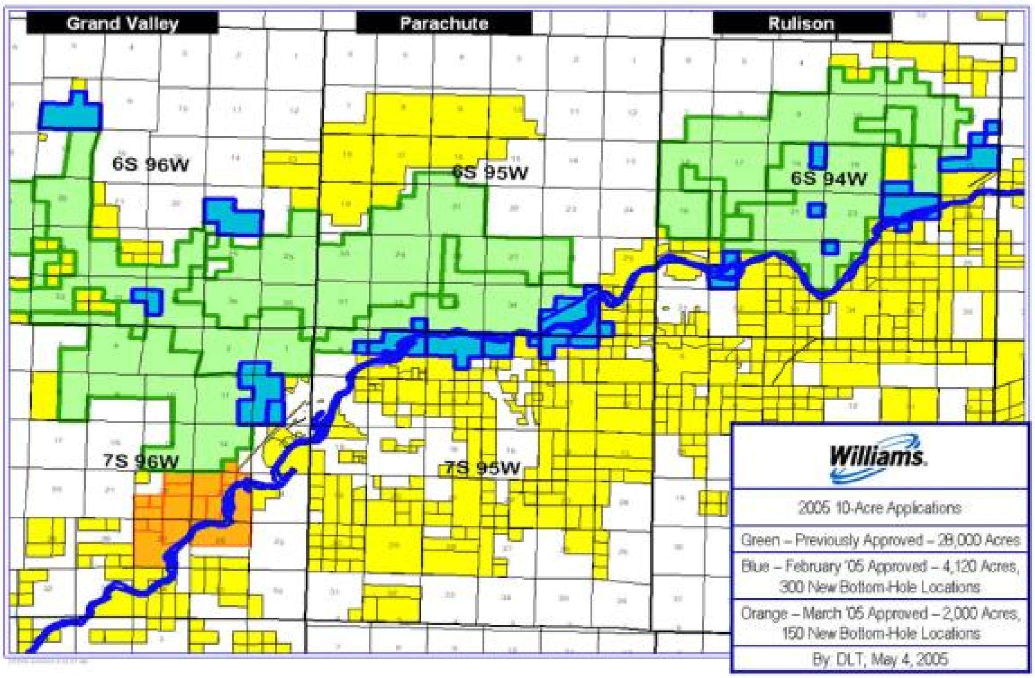
Exploration & Production

Piceance Basin
2005 Approved 10-Acre Applications



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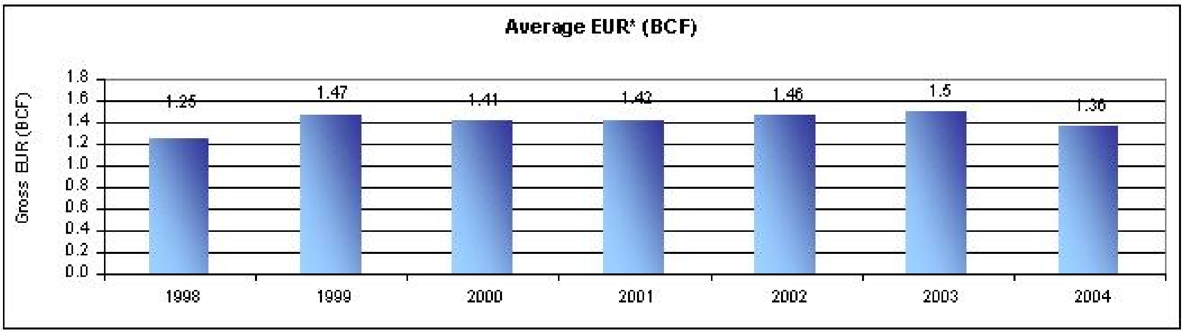
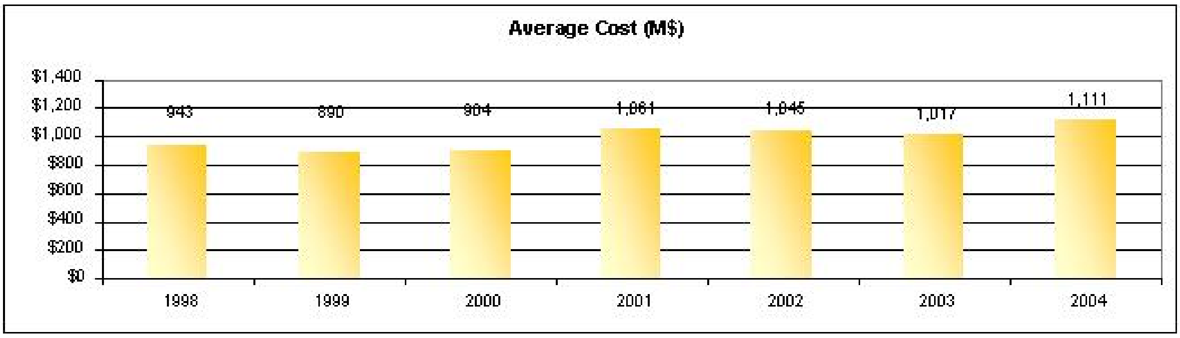
Piceance Basin
Record of Capital and EUR





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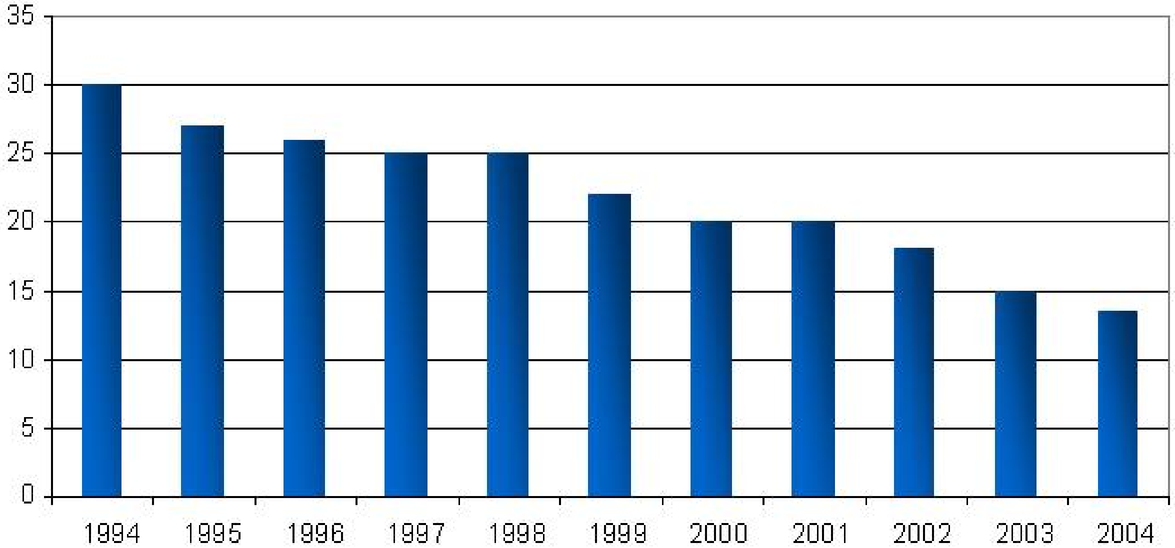
Piceance Basin
Drilling Efficiency



* Days from spud to rig release. Does not include rig move time.

Exploration & Production

Purpose Build Rig Program

- Piceance Rig Design
  - Improved performance in Piceance Basin drilling conditions
  - Reduce the number and size of surface locations
- H&P Deal
  - Total 10 rigs
  - 3 year commitment
  - First delivery November 2005

Incremental Activity

	2005	2006	2007
Operated Spuds	3	125	150
Rigs	0	6	8
Capital $MM *	~30	~200	~200
Segment Profit $MM	0	~30	~50
Production MMCFD	0	~20	~50

* Capital of $30 million in '05 and $115 million in '06 are for Facilities

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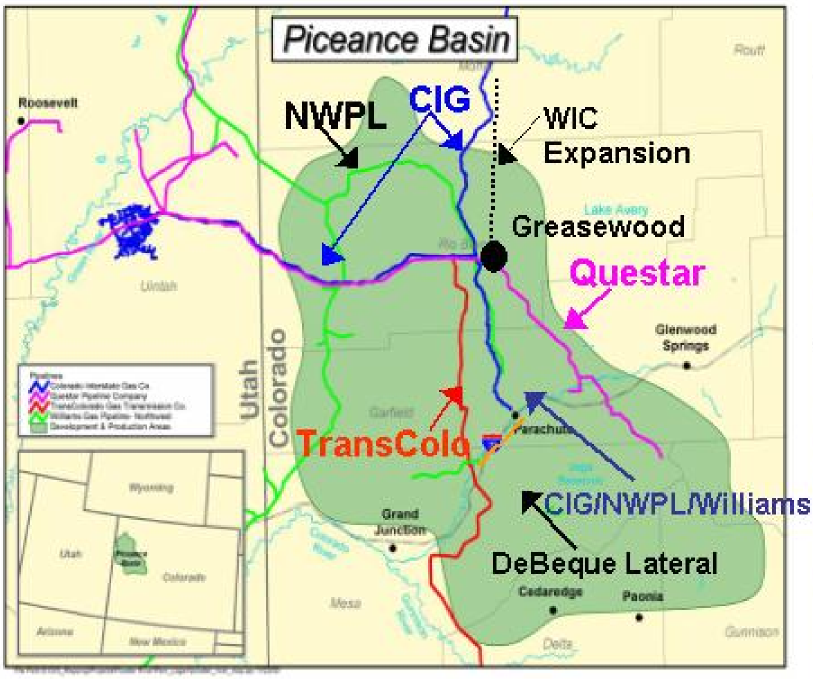
Exploration & Production

Piceance Basin
Pipeline Infrastructure Capacity

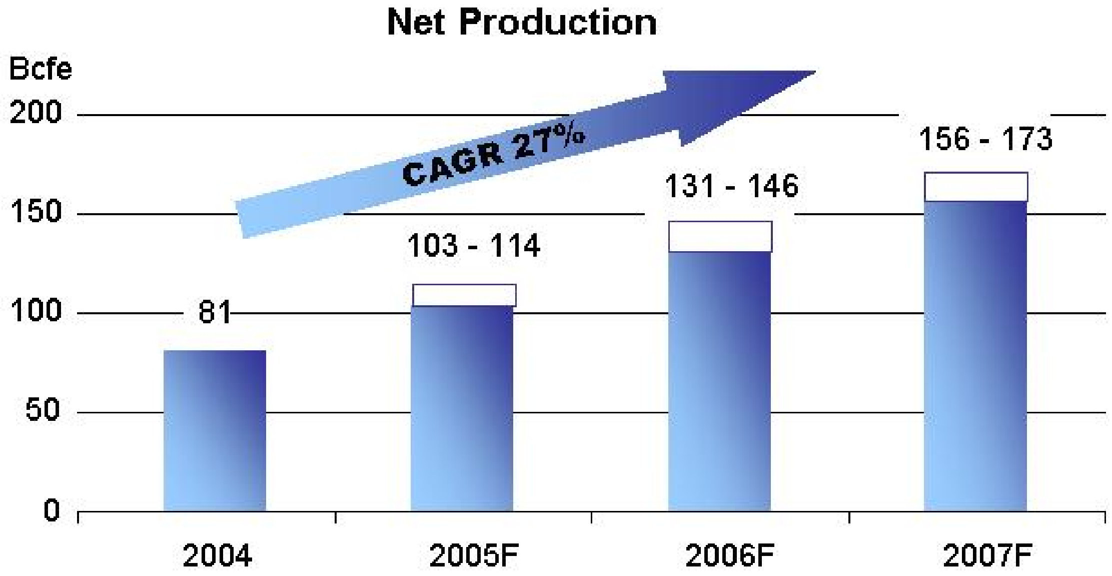


Gathering & Processing:
- Currently 600 MMcf/d
- Greasewood line
- DeBeque Lateral
- Rifle interconnect
- CIG interconnect

Transport:
- TransColorado to San Juan
- TransColorado to Greasewood
- WIC expansion
- CIG
- NWPL

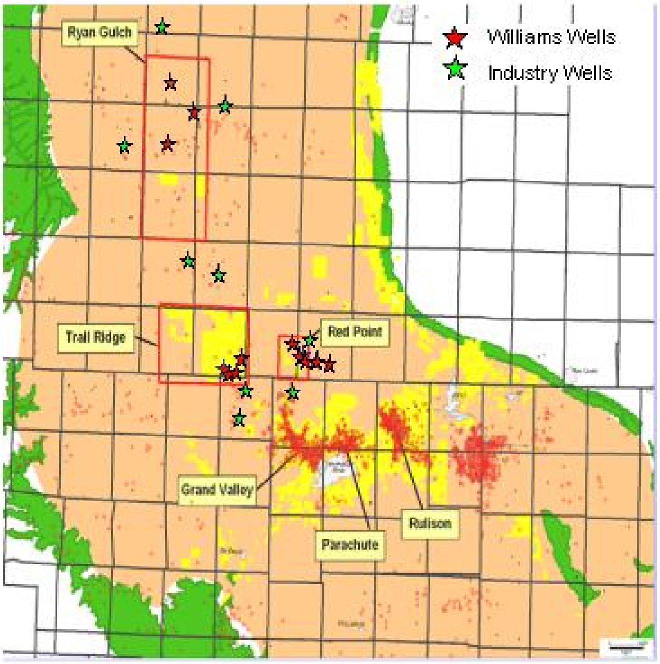
Exploration & Production

Piceance Basin
Positioned for Continuing Valley Growth



	2004	2005F	2006F	2007F
Wells Spud	243	260 - 280	400 - 450	450 - 500
Net MMcfe/d	222	282 - 313	359 - 401	427 - 475

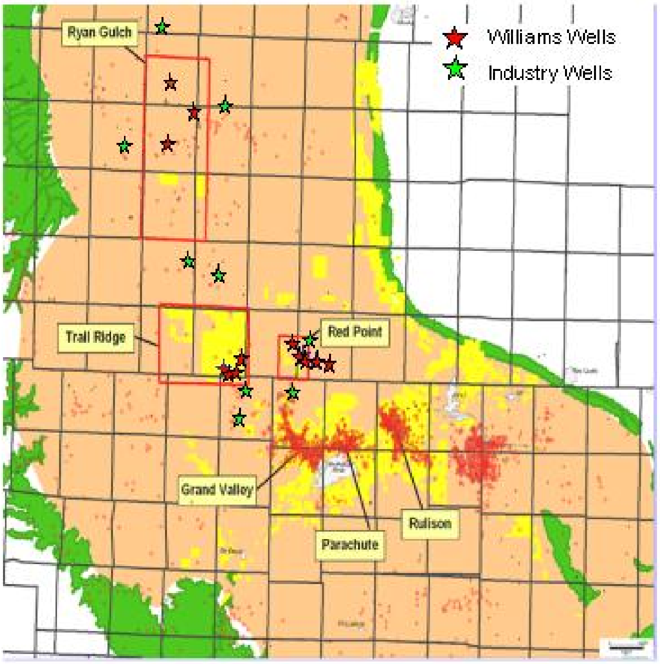
Additional Piceance Basin Opportunities
Ryan Gulch Project Area



- Earn 28,383 gross / 14,475 net acres
- Drilling obligations – 6 wells in 2 years; 3 Drilled, 3 remaining
- Williams operated at 51% WI
- 87% average NRI
- ~770 potential gross well locations
- ~700 net Bcf potential reserves
- Contiguous acreage block

Exploration & Production

Additional Piceance Basin Opportunities
Trail Ridge Project Area



- 17,316 gross/14,545 net acres
- Drilling obligation – 4 wells/year for 6 years
- 84% average NRI
- Williams operated at 100% WI
- ~500 potential well locations
- ~500 BCF potential reserves
- Contiguous acreage block
- 6 miles West of Grand Valley where completions average 1.2 Bcf/well
- Produces into Williams' Grand Valley Gathering System

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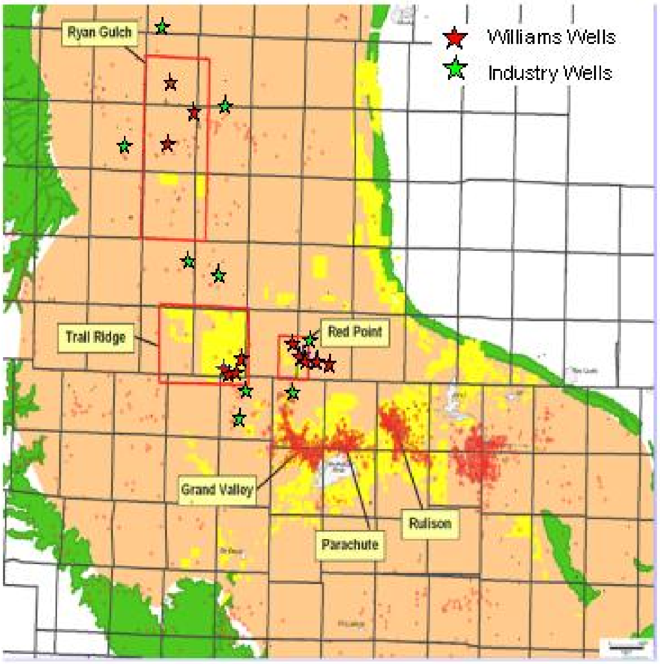
Additional Piceance Basin Opportunities
Red Point Project Area



- 1,908 gross and net acres
- 85% average NRI
- 189 potential well locations
- ~200 Bcf potential reserves, at 1.3 BCF/well
- Adjacent well, which has a 1.3 Bcf Estimated Ultimate Recovery (EUR)
- Produces into Williams' Grand Valley Gathering System

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Additional Piceance Basin Opportunities
Summary

Prospect	Net Acres	Gross Potential Locations*	Net Potential Reserves*(BCF)
Ryan Gulch (40 acre spacing)	14,475	770	700
Trail Ridge (40 acre spacing)	14,545	500	500
Red Point (10 acre spacing)	1,908	189	200
Total	30,928	1,459	1,400

* Not included in US Reserves summary of 2.7 Tcf proved and ~7 Tcf proved, probable and possible.

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Exploration & Production

2005-2007 Guidance

1Q05 Earnings Call

Dollars in millions

	2005	2006	2007
Segment profit	$400 - 475	$480 - 555	$550 - 675
Annual DD&A	$235 - 265	$280-320	$350-400
Segment Profit + DD&A	$635 - 740	$760 - 875	$900 - 1075
Capital spending	$530 - 605	$725 - 825	$725 - 875
Production (MMcfe/d)	600 - 700	720 - 820	825 - 925
Hedges (NYMEX Equivalent)			
Fixed Price:			
Volume (MMcfe/d)	284	298	172
Price (Mcfe)	$4.46	$4.39	$4.18
Collar:			
Volume (MMcfe/d)	50	65	15
Price (Mcfe)	$6.75 - $8.50 2Q-YE	$6.62 - $8.42	$6.50 - $8.25

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Key Points

- Delivering meaningful volume growth through expanded development drilling activity -- Piceance is primary growth driver
- Long history of high drilling success, low finding costs
- Short time cycle investments, fast cash returns
- Maintaining top quartile cost and efficiency position
- Long-term repeatable drilling inventory of significant proved undeveloped, probables, and possibles
- Exciting new opportunities
  - Trail Ridge, Ryan Gulch, Red Point, and Caney Shale
- Strategy remains rapid development of our premier drilling inventory

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Q&A

Questions?

Appendix

May 12, 2005

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Appendix: Power

Estimated Total Cash Flows

Undiscounted dollars in millions

Combined Power Portfolio Estimated as of 3/31/05	Q1A	2005A+F	2006F	2007F	2008-2010F	2011-2022F
Tolling Demand Payment Obligations	($89)	($368)	($402)	($406)	($1,233)	($3,868)
Resale of Tolling	$41	$126	$106	$96	$158	$0
Full Requirements	($2)	$3	($7)	$0	$6	$26
Long-term Physical Forward Power Sales	$22	$25	($13)	($1)	$29	$0
OTC Hedges	$34	$146	$205	$66	$107	$58
Estimated Hedged Tolling Revenues	$15	$184	$279	$283	$588	$279
Subtotal	$21	$116	$168	$38	($345)	($3,505)
Estimated Merchant Cash Flows	$0	$79	$28	$156	$873	$5,850
Est. Combined Power Portfolio Cash Flows	$21	$195	$196	$194	$528	$2,345
Est. NG Portfolio Cash Flows	$11	($14)	$1	$5	$70	($63)
SG&A and Other	($26)	($81)	($73)	($75)	($225)	($800)
Subtotal	$6	$100	$124	$124	$373	$1,482
Working Capital and Other	$42	$23	$1	$3	$6	$103
Estimated Cash Flows After SG&A	$48	$123	$125	$127	$379	$1,585
Capacity Available (in MW)		5,149	7,723	7,723	7,723	7,723
Expected Output (in MW)		1,533	2,289	2,530	2,917	3,479
Total Volume Hedged (in MW)		1,461	1,977	1,867	1,172	136
Percentage Volume Hedges		95%	91%	73%	40%	5%

Est Demand Payment Coverage through 2010 - hedged		
Total Estimated Hedged Cash Flows	$	2,386
Total Demand Payments	$	(2,409)
Cost Coverage		0.99

Note: Actual cash flows realized may differ materially from those shown. Price hedges do not hedge 100% of Estimated Hedged Tolling Revenue.
Note: 2005 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.
Note: Est. NG Portfolio Cash Flows represent expected cashflows from NG Storage, Transport and hedges.

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West – Estimated Total Cash Flows

Undiscounted dollars in millions

West Power Portfolio Estimated as of 3/31/05	**Q1A**	**2005A+F**	**2006F**	**2007F**	**2008-2010F**	**2011-2018F**
Tolling Demand Payment Obligations	($38)	($141)	($156)	($157)	($482)	($1,243)
Resale of Tolling	$41	$126	$106	$96	$158	$0
Long-term Physical Forward Power Sales	$22	$22	($13)	($1)	$29	$0
OTC Hedges	$27	$101	$145	$44	$52	($4)
Est. Tolling Cash Flows Associated With Hedge	$4	$141	$191	$201	$396	$16
Subtotal	$56	$249	$273	$183	$153	($1,231)
Estimated Merchant Cash Flows	$0	$48	$10	$70	$439	$2,607
Estimated Cash Flows	$56	$297	$283	$253	$592	$1,376
Capacity Available (in MW)		2,761	4,141	4,141	4,141	4,141
Expected Output (in MW)		938	1,314	1,383	1,556	1,790
Total Volume Hedged (in MW)		927	1,170	1,196	738	12
Percentage Volume Hedges		99%	89%	87%	47%	1%

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

Note: 2005 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

Central – Estimated Total Cash Flows

Undiscounted dollars in millions

Mid-Continent Power Portfolio Estimated as of 3/31/05	Q1A	2005A+F	2006F	2007F	2008-2010F	2011-2020F
Tolling Demand Payment Obligations	($13)	($83)	($88)	($89)	($271)	($831)
Long-term Physical Forward Power Sales	$0	$3	$0	$0	$0	$0
OTC Hedges	($3)	($13)	($3)	$0	($15)	($9)
Est. Tolling Cash Flows Associated With Hedge	$1	$16	$24	$20	$24	$0
Subtotal	($15)	($77)	($67)	($69)	($262)	($840)
Estimated Merchant Cash Flows	$0	$0	$10	$29	$202	$1,104
Estimated Cash Flows	($15)	($77)	($57)	($40)	($60)	$264
Capacity Available (in MW)		871	1,306	1,306	1,306	1,306
Expected Output (in MW)		182	304	355	446	608
Total Volume Hedged (in MW)		180	215	143	48	0
Percentage Volume Hedges		99%	71%	40%	11%	0%

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

Note: 2005 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

Appendix: Power

East – Estimated Total Cash Flows

Undiscounted dollars in millions

East Power Portfolio Estimated as of 3/31/05	**Q1A**	**2005A+F**	**2006F**	**2007F**	**2008-2010F**	**2011-2022F**
Tolling Demand Payment Obligations	($34)	($143)	($158)	($160)	($480)	($1,794)
Resale of Tolling	$0	$0	$0	$0	$0	$0
Full Requirements	($2)	$3	($7)	$0	$6	$26
Long-term Physical Forward Power Sales	$0	$0	$0	$0	$0	$0
OTC Hedges	$14	$58	$63	$22	$70	$70
Est. Tolling Cash Flows Associated With Hedge	$1	$27	$64	$63	$168	$264
Subtotal	($21)	($55)	($38)	($75)	($236)	($1,434)
Estimated Merchant Cash Flows	$0	$30	$9	$56	$233	$2,139
Estimated Cash Flows	($21)	($25)	($29)	($19)	($3)	$705
Capacity Available (in MW)		1,517	2,276	2,276	2,276	2,276
Expected Output (in MW)		413	671	792	915	1,081
Total Volume Hedged (in MW)		344	591	528	386	124
Percentage Volume Hedges		83%	88%	67%	42%	11%

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

Note: 2005 Actual Merchant Cash Flows are included in Estimated Hedged Tolling Revenues.

Appendix: Power

Segment Profit

1Q05 Earnings Call

Dollars in millions	1st Quarter 2005	2004
Gross Margin	$140	($2)
SG&A	(16)	(16)
Op. & Other Inc / (Expense)	(10)	(14)
Segment Profit	**$114**	**$(32)**
Nonrecurring:		
Expense related to prior period and other	11	-
Recurring Segment Profit	**125**	**(32)**
MTM Adjustments	**(108)**	**112**
Recurring Segment Profit after MTM Adjustments	**$17**	**$80**

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Appendix: Power

Segment Profit to Cash Flow

1Q05 Earnings Call

Dollars in millions

	Power & Natural Gas	Other	Total
Gross Margin	$140		$140
SG&A & Other Inc/(Exp)	(26)		(26)
Segment Profit	$114	$0	$114
MTM Adjustments:			
Reverse Forward Unrealized MTM (Gains)	(221)		(221)
Add Realized Gains from MTM previously recognized	113		113
Segment Profit after MTM Adjustments	$6	$0	$6
Total Working Capital Change		42	42
Power Segment CFFO	$6	$42	$48
Est. Working Capital Used for Other BU's		13	13
Power Segment Standalone CFFO	$6	$55	$61

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Appendix: Power

Cash Flow Variance Analysis

1Q05 Earnings Ca...

Undiscounted dollars in millions

Combined Power Portfolio *Actual 1Q05 v. Forecast 1Q05*	**1Q05 A**	**1Q05 F**
Tolling Demand Payment Obligations	($89)	($84)
Resale of Tolling	41	40
Full Requirements	(2)	(1)
Long-term Physical Forward Power Sales	22	21
OTC Hedges	34	33
Estimated Merchant Cash Flows	15	10
Total Cash Flows	$21	$19
Working Capital & Other	53	76
SG&A and Other	(26)	(17)
Estimated Cash Flows After SG&A	$48	$78

Note: 1Q05 forecast estimated as of 12/30/04. 1Q05 actual cash flows agree in total with Power's Cash Flow Statement; however the allocation of actual cash flows to the various deal types is based on estimates.

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Enterprise Risk Management

Dollars in millions	As of 3/31/05 E&P	Midstream	Power	Corp./ Other	Total	12/31/04 Total
Margins & Ad. Assur.	$70	$1	$87	-	$158	$134
Prepayments	-	4	27	-	31	40
Subtotal	**$70**	**$5**	**$114**	**$ -**	**$189**	**$174**
Letters of Credit	496	104	257	90	947	855
Total as of 3/31/05	**$566**	**$109**	**$371**	**$90**	**$1,136**	**$1,029**
Total as of 12/31/04	**$449**	**$135**	**$350**	**$95**	**$1,029**	
Change	**$117**	**($26)**	**$21**	**($5)**	**$107**	

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Enterprise Risk Management

Dollars in millions

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

	3/31/05	12/30/04
– 30 days	($124)	($106)
– 180 days	($328)	($268)
– 360 days	($341)	($353)

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

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Enterprise Risk Management
Sensitivity Scenarios in millions

	WMB [1] Natural Gas (Per MMBTU)	E&P [2] Natural Gas (Per MMBTU)	Midstream [3] Processing Margin (Per Gallon)	Power [4] West Spark Spread (Per MWh)
Price Increase	$0.10	$0.10	$0.01	$5.00
2005	($3) - $0	$5 - $6	$7 - $12	$5 - $10
2006	($2) - $1	$10 - $11	$10 - $15	$5 - $15
2007	$8 - $11	$16 - $17	$10 - $15	$5 - $15

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

[2] Assumes a price increase on E&P position only (production and hedges).

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

[4] Assumes a non-correlated change in West power prices only, no change in power volatility, full extrinsic value not included.