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): February 19, 2004

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)

Item 7. Financial Statements and Exhibits.

(a) None

(b) None

(c) Exhibits

Exhibit 99.1	Copy of Williams' slide presentation to be utilized during the February 19, 2004, public conference call and webcast.
Exhibit 99.2	Copy of Williams' press release dated February 19, 2004, publicly announcing its 2003 financial results.
Exhibit 99.3	Copy of Williams' Reconciliation of Income (Loss) from Continuing Operations to Recurring Earnings and Reconciliation of Segment Profit (Loss) to Recurring Segment Profit (Loss).

Item 9. Regulation FD Disclosure.

The Williams Companies, Inc. ("Williams") wishes to disclose for Regulation FD purposes its slide presentation, filed herewith as Exhibit 99.1, to be utilized during a public conference call and webcast on the morning of February 19, 2004.

Item 12. Results of Operations and Financial Condition.

On February 19, 2004, Williams issued a press release announcing its financial results for the year ended December 31, 2003. The press release is accompanied by a reconciliation of certain non-GAAP financial measures disclosed in the press release with the GAAP financial measures that Williams' management believes are most directly comparable. A copy of the press release and the reconciliation are furnished as a part of this current report on Form 8-K as Exhibit 99.2 and Exhibit 99.3, respectively, and are incorporated herein in their entirety by reference.

This Report on Form 8-K is being furnished pursuant to Item 12, 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 filing under the Securities Act of 1933, as amended.

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: February 19, 2004

/s/ Brian K. Shore

Name: Brian K. Shore
Title: Corporate Secretary

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
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EXHIBIT 99.1

Williams

Williams Analyst Conference Call 2003 Results

February 19, 2004

Forward Looking Statements

Williams

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" with in 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:

- Our ability to divest successfully certain assets and our ability to identify and achieve cost savings measures, which may be dependent on factors outside of our control;
- Our ability to timely divest our wholesale power and energy trading business which may be dependent on factors outside of our control;
- 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 might require us to provide increasing amounts of credit support;
- 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 risk measurement and hedging activities might not prevent losses;
- 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 the energy marketing and trading business;
- 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;
- The different regional power markets in which we compete or will compete in the future have changing regulatory structures;
- 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;
- 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 U.S. and Canadian natural gas transmission and midstream businesses;
- Our gathering, processing and transporting activities involve numerous risks that might result in accidents and other operating risks and costs;
- The threat of terrorist activities and the potential for continued military and other actions; and
- The historic drilling success rate of our exploration and production business is no guarantee of future performance.

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.

Agenda

Williams

■ 2003 Review	Steve Malcolm
■ 2003 Financial Review	Don Chappel
■ Business Unit Review and Outlook	
– Exploration & Production	Ralph Hill
– Gas Pipeline	Doug Whisenant
– Midstream	Alan Armstrong
– Power	Bill Hobbs
■ 2004-2006 Consolidated Outlook	Don Chappel
■ Summary	Steve Malcolm
■ Q&A	

2003 Review

Steve Malcolm
President, Chairman & CEO

Strategy

Williams

Commercial

- Natural gas assets in key growth markets where we enjoy the competitive advantages of scale, low-cost position and market leadership

Financial

- Create and maintain adequate liquidity from all available sources to fully support business strategy
- De-leverage through combination of asset sales, refinancing, cost-cutting
- Develop balance sheet capable of supporting and ultimately growing business and value

A Work in Progress

Initiate & Stabilize → Execute Restructuring → Emerge

Measures of Success

Initiate & Stabilize	Execute Restructuring	Emerge
☑ Avoid bankruptcy	☑ Complete asset sales	☑ Position company for integrated natural gas growth
☑ Address liquidity crisis	☑ Rationalize cost structure	☐ Optimize capital structure
☑ Restore customer and supplier confidence	☑ Manage liquidity	☐ Capitalize on strategic position
	☑ De-lever	
	☑ Restore confidence of and gain access to capital markets	

Restructuring Success Measures

Williams

- Asset sales program 90% complete
  - $3.0 billion net proceeds in 2003; $6.1 billion since 2002
- Rationalize cost structure
  - 30% reduction in continuing ops SG&A costs; efforts continue
- Manage liquidity
  - $2.3 billion in available cash and equivalents at year-end
- De-lever
  - Net $2 billion decrease in debt in 2003
  - Will meet the March 15 retirement of remaining 9.25% notes
- Restore confidence of and gain access to capital markets
- Solid operating performance

Pending Asset Sales

- Announced but not closed $265 million
  - Alaska Refinery 1Q04

- Identified for sale totaling $500-600 million
  - Midstream Assets 2Q/3Q/4Q04
  - Western Canada Assets (Straddle Plants) 3Q04

Power Restructuring Outlook

Williams

- Actively pursuing full exit of power business
  - Sold or liquidated nearly $600 million of power-related assets and contracts since June 2002
  - Agreed to terminate contract with Allegheny
  - Managing in the interim to
    - Reduce risk
    - Generate cash
    - Meet contractual commitments
  - Exit timing and value uncertain
    - Remaining positions complex
    - Power markets have deteriorated
    - Positive exit value in West; negative exit value in remainder
  - Held Tutorial on November 21 to provide greater clarity

Path Ahead

- Focus on strong business performance
- Disciplined investment in core businesses
- Continued restructuring
  – De-levering
  – Complete asset sale program
  – Cost reductions
  – Power
- Position for future growth that creates economic value

2003 Financial Review

Don Chappel, CFO

2003 Results

Williams

Dollars in millions (except per share amounts)

	4Q03	4Q02	2003	2002
Income (Loss) from Continuing Ops.*	($97)	($151)	$3	($612)
Income (Loss) from Discont. Ops.	31	(68)	254	(143)
Effect of Accounting Change	-	-	(761)	-
Net Loss*	($66)	($219)	($504)	($755)
Net Loss / Share*	($0.13)	($0.44)	($1.03)	($1.63)
Recurring Inc./(Loss) from Cont. Ops**	$57	$47	$12	($222)
Rcr. Inc./(Loss) from Cont. Ops /Share**	$0.11	$0.09	$0.02	($0.43)

* Includes gains and impairments on asset sales and prior period adjustments

** A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com.

4th Quarter
Recurring Income from Continuing Operations

Williams.

Dollars in millions	4Q03	4Q02	Difference
Income (Loss) from Cont. Ops.	**($97)**	**($151)**	**$54**
Gains on Asset Sales	(16)	2	(18)
Impairments/Losses/Write-offs	131	253	(122)
Debt Tender Expenses	67	-	67
Cal. Refund & Other Accrual Adj.	33	-	33
Other - Net	-	2	(2)
Less: Income Tax Provision	61	52	9
Recurring Income from Cont. Op.	$57	$54	$3
Preferred Dividend	-	(7)	7
Rec. Inc. from Cont. Op. Avail. To Common	**$57**	**$47**	**$10**
Recurring Income from Cont. Op/Share	**$0.11**	**$0.09**	**$0.02**

A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com.

Full Year
Recurring Income from Continuing Operations

Williams.

Dollars in millions	2003	2002	Difference
Income (Loss) from Cont. Ops.	**$3**	**($612)**	**$615**
Gains on Asset Sales	(337)	(220)	(117)
Impairments/Losses/Write-offs	279	728	(449)
Expenses on Debt Tender	67	-	67
Income Related to Prior Periods *	(105)	-	(105)
Cal. Refund & Other Accrual Adj	33	-	33
Other - Net	45	110	(65)
Less: Income Tax Provision	(57)	138	(195)
Recurring Income from Cont. Op.	$43	($132)	$174
Preferred Dividend	(30)	(90)	60
Rec. Inc./(Loss) from Cont. Op. Avail. To Com.	**$12**	**($222)**	**$234**
Rec. Income/(Loss) from Cont. Op/Share	**$0.02**	**($0.43)**	**$0.45**

* See Note 1 in 2Q 2003 10Q for description

A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com.

2003 Segment Profit

Williams

Dollars in millions	Reported		Recurring	
	2003	**2002**	**2003**	**2002**
Gas Pipelines	$555	$545	$581	$574
Exploration & Production	401	509	310	368
Midstream Gas & Liquids	286	183	319	309
	$1,242	$1,237	$1,210	$1,251
Power**	134	(625)	(25)	(353)
Other	(50)	14	(10)	(28)
Segment Profit*	$1,326	$626	$1,175	$870

*Reported segment profit Includes gains and impairments
** Reported 2003 segment profit for Power includes income related to prior periods

- A schedule reconciling income (loss) from continuing operations to recurring income from continuing operations is available on Williams' Web site at www.williams.com.

2003 EBITDA Reconciliation

Williams

Dollars in millions

Net (Loss)*	**($504)**
Cum. Effect of Change in Acct. Principle	761
Income from Disc. Operations	(254)
Net Interest Expense	1,243
DD&A	671
Provision for Income Taxes	29
EBITDA*	**$1,946**

* Includes gains and impairments on asset sales and prior period adjustments

2003 Segment Contributions

Williams.

Dollars in millions

	Gas Pipes	E&P	Midstream	Power	Corp/Other	Total
Segment Profit (Loss) *	$555	$401	$286	$134	($50)	**$1,326**
DD&A	247	174	199	31	20	**671**
Segment Profit before DDA	**$802**	**$575**	**$485**	**$165**	**($30)**	$1,997
General Corporate Expense						**(87)**
Investing Income**						**78**
Other Income						**(42)**
TOTAL						**$1,946**

* Includes gains and impairments on asset sales and prior period adjustments
**Excluding equity earnings and income (loss) from investments contained in segment profit

2003 Cash Information

Williams

Dollars in millions	4Q03	2003
Beginning Cash*	**$3,431**	**$1,736**
Cash Flow from Operations	75	770
Capital Expenditures/Investments	(353)	(1,107)
LC Collateral	60	(388)
Retirements (Debt & Pref. Stock)	(1,221)	(3,425)
Asset Sales	174	2,983
Debt Proceeds	230	2,006
Other-Net	(79)	(257)
Ending Cash*	**$2,318**	**$2,318**
Restricted Cash		**$207**

* Includes cash for discontinued operations of $2.6 million at 12/31/03, $2.9 million at 9/30/03 and $85.6 million at 12/31/02

Debt Balances 2003

Williams

	Dollars in millions	Avg. Cost
Debt Balance @ 12/31/02 (1), (2)	**$13,991**	
Debt Associated with Discontinued Operations	(897)	
Debt Balance Adjusted for Disc. Oper. @ 12/31/02	**13,094**	**10.0%**
Scheduled & Tendered Debt Retirements	(1,742)	
Progeny Debt Payments	(460)	
Accreted Capitalized Interest	69	
Lehman/Berkshire Loan Prepayment	(988)	
New Debt Issues (3)	2,006	
Debt Balance @ 12/31/03	**$11,979**	**7.7%**
Net Decrease in Debt	**$2,012**	
Net Increase in Cash (incl. Disc. Operations)	**$ 583**	
	$2,595	

(1) Debt is long-term debt due within 1 year plus long-term debt plus notes payable
(2) Includes FELINE PACS
(3) Includes $300MM junior subordinated debt issued to retire preferred stock

Enterprise Risk Management

Williams

Estimated dollars in millions	**E&P**	**Midstream**	**Power**	**Corp./ Other**	**Total**
Margins & Ad. Assur.	$281	$ 44	$202	-	$527
Prepayments	-	12	139	-	151
Subtotal	**$281**	**$56**	**$341**	**$ -**	**$678**
Letters of Credit	3	-	190	185	378
Total as of 12/31/03	**$284**	**$56**	**$531**	**$185**	**$1,056**
Total as of 12/31/02					**$1,131**
Change					**($75)**

Enterprise Risk Management

Williams

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

– 30 days	($183) million
– 180 days	($324) million
– 360 days	($349) million

Assumption:
- The margin numbers above consist of only the forward marginable position values, starting from February 2004. Does not include adequate assurance, prepayments or other spot monthly liquidity requirements.

Enterprise Risk Management

Williams

Estimated dollars in millions

Sensitivities Analysis

	WMB [1] Natural Gas (Per MMBTU)	Power[2] West Spark Spread Power Price (Per MWh)	Midstream [3] Processing Margin NGL Price (Per Gallon)
Price Increase	$0.10	$5.00	$0.01
2004	($5)	$0-5	$10-15
2005	$4	$5-10	$10-15
2006	$11	$5-15	$10-15

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

[2] Assumes a non-correlated change in West power prices only, no change in power volatility, full extrinsic value not included. Heat rate and position change associated with Spark Spread increase is consistent across all months. Cash flow ranges are not linear.

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

Business Unit Review and Outlook

Exploration & Production

Ralph Hill, Senior VP

Exploration & Production
Segment Profit

Williams

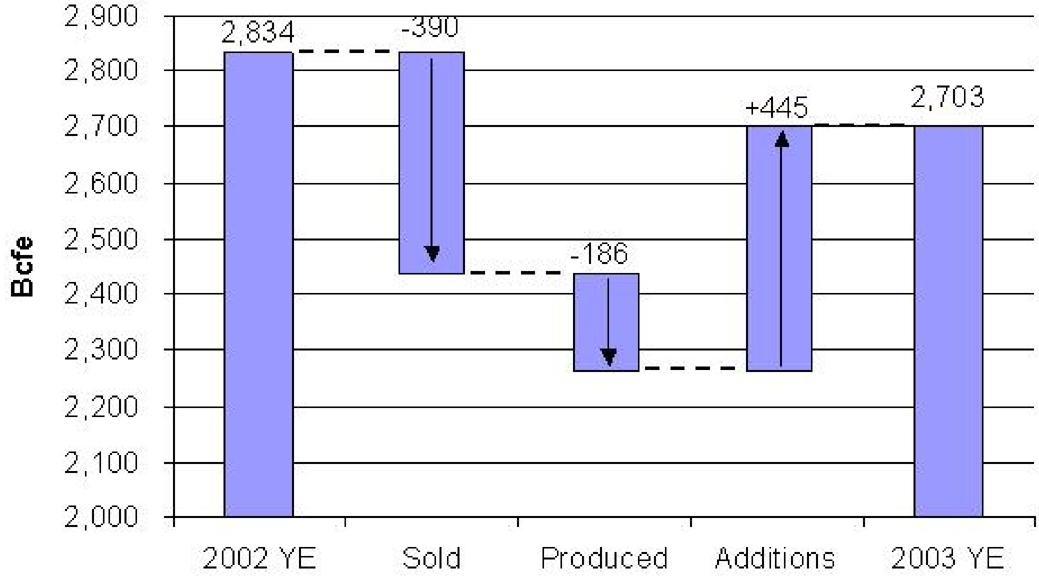
Dollars in millions	4th Quarter			
	2003	2002	2003	2002
Segment Profit	$50	$82	$401	$509
Includes				
▪ (Gain)/Loss on Asset Sale	-	3	(91)	(141)
Recurring Segment Profit	$50	$85	$310	$368

- Recurring segment profit declined due to expiration of Section 29 tax credits of $8 million in 4Q02 and $34 million in 2002 with remainder of decrease primarily due to lower volumes resulting from asset sales

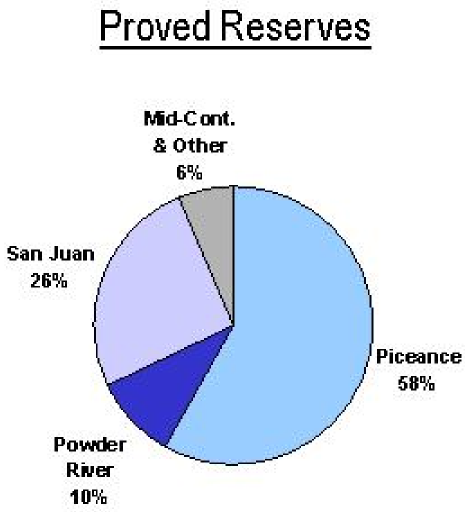
Exploration & Production
4Q/YE 2003 Accomplishments

- 4Q Increased Drilling Activity
  - Piceance rig count increased to 8 rigs from 1 in 2Q
  - San Juan added 1 drilling rig and 4 cavitation rigs
- Reversed volume decline during fourth quarter
- Completed backyard acquisition of working interest partner in Arkoma
- 2003 production replaced at a ratio of 254%
- 2003 drilling success rate of 99%
- Moved 412 Bcf from Probable to Proved Reserves, 2.7 Tcf total reserves at 12/31/03

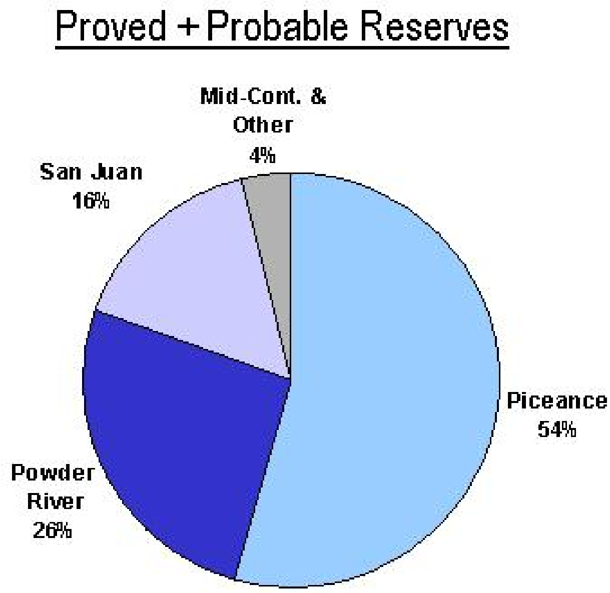
Exploration & Production
Proved Reserves Reconciliation



Exploration & Production
2003 Year End U.S. Reserves



TOTAL: 2.7 Tcf Proved



Exploration & Production
2004-2006 Guidance

Dollars in millions	**2004**	**2005**	**2006**
Segment profit	$275-340	$350-450	$400-500
Annual DD&A	$160-180	$195-225	$230-260
Capital spending	$300-350	$400-450	$450-500
Production (MMcfed)	500-550	600-700	700-800

Exploration & Production
Arkoma Basin Overview

- Horizontal Hartshorne CBM drilling
- Geographic extent of coal offers growth opportunities
- In-fill, field extension drilling
- Proprietary low-pressure gathering system constructed in 2002
- Key characteristics
  - 122 Bcfe total proved reserves
  - 17 MMcf/d net production
  - Leasehold 58,000 net acres
  - 168 total wells, 90% operated
  - 160 acre development spacing
  - 2003 drilling success rate of 94%

Exploration & Production
San Juan Basin Overview

- Conventional and coalbed methane production
- Long life / slow decline wells
- Low risk in-fill drilling via downspacing and EIS
- Good pipeline infrastructure / market access
- Key characteristics
  - 702 Bcfe total proved reserves
  - 136 Mmcf/d net production
  - Leasehold 94,000 net acres
  - 714 operated and 1,400+ joint interest wells
  - 2003 drilling success rate of 100%

Exploration & Production
Powder River Basin Overview

- High potential, low-risk development play
- Low cost wells
- Typical well production
  - Wyodak - 140 Mcf/d peak
  - Big George - 400Mcf/d peak
- Key characteristics
  - 257 Bcfe total proved reserves
  - 114 MMcf/d net production
  - Leasehold 1,021,400 gross/457,900 net acres
  - 4,109 total wells, 50% operated
  - 2003 drilling success rate of 99%
  - 10,980 drilling locations

Exploration & Production
Powder River Basin - Update

- 660 Federal Well Permits issued to the industry post Record of Decision (ROD)
  - Williams received 140 (21%) and partner 61 for total of 201(30%)
- 74 of 140 wells spudded post-ROD
- 1,400 industry permits in the approval process; 352 for Williams and partner
- BLM's goal is to issue 3,000 permits per year, ongoing streamlining process
- Big George is now producing 118 MMcfd or 12% of Powder River Basin production

Exploration & Production

Piceance Basin Overview

- Large gas-saturated, basin-centered gas trap
- High return/low risk economics
- Key characteristics
  - 1.6 Tcfe total proved reserves
  - 172 MMcf/d net production
  - Leasehold 173,800 gross /129,900 net acres
  - 2,500 drilling locations, > 10 yr inventory
  - 802 total operated wells, high working interest
  - 2003 drilling success rate of 100%
  - 10 rigs operating, increasing to 12 rigs during the year

Exploration & Production
Basin Comparison

Typical 2004 Well Economics

	Arkoma	Powder River	San Juan Coal	Piceance
Cost/well ($/M)	$375	$145	$583	$1,030
Typical well reserves (Bcf)	0.8	0.5	1.5	1.3
Drilling costs ($/Mcfe)	$0.55	$0.35	$0.44	$0.93
LOE ($/Mcfe)	$0.58	$0.24	$0.39	$0.17
Incremental IRR	73%	57%	67%	56%
Net Margin ($/Mcfe)	$2.71	$2.24	$1.98	$3.18

Exploration & Production

Hedging

- 2004 - 80% hedged at $4.03 NYMEX
- 2005 - 47% hedged at $4.44 NYMEX
- 2006 - 40% hedged at $4.39 NYMEX
- Basis hedges in place to mitigate location risk
- Future hedging strategy will continue to be a function of Williams' portfolio

Challenges and Opportunities

- Challenges
  - Pace of drilling permit approvals
  - Rig availability
- Opportunities
  - BLM committed to streamlining
  - Williams has successfully obtained additional rigs
  - Opportunity to increase drilling pace beyond planned rate
  - Numerous backyard investment and acquisition opportunities

Exploration & Production
Platform for Growth

Williams

- Conservative business strategy
- Investments are short time cycle, fast cash returns
- High-quality, low-risk reserve base
- History of high success, low finding costs
- Diverse producing basins, long term drilling inventory
- Significant probables and possibles inventory
- Low-cost, high-margin producer
- Experienced management team
- Talented work force

Gas Pipeline

Doug Whisenant, Senior VP

Gas Pipeline Assets

Williams

Gas Pipeline
Segment Profit

Williams

Dollars in millions	4th Quarter 2003	2002	2003	2002
Segment Profit	$148	$122	$555	$545*
Includes				
▪ Write-off projects	-	5	25	19
▪ Gulfstream Project completion fee	-	-	-	(27)
▪ Early retirement/realignment	-	-	1	15
▪ Net gains/losses/impairments	-	16	-	22
Recurring Segment Profit	$148	$143	$581	$574

* 2002 includes $26 million Transco rate case settlement and $27 million Gulfstream AFUDC

Gas Pipeline
4Q 2003 Accomplishments

Williams

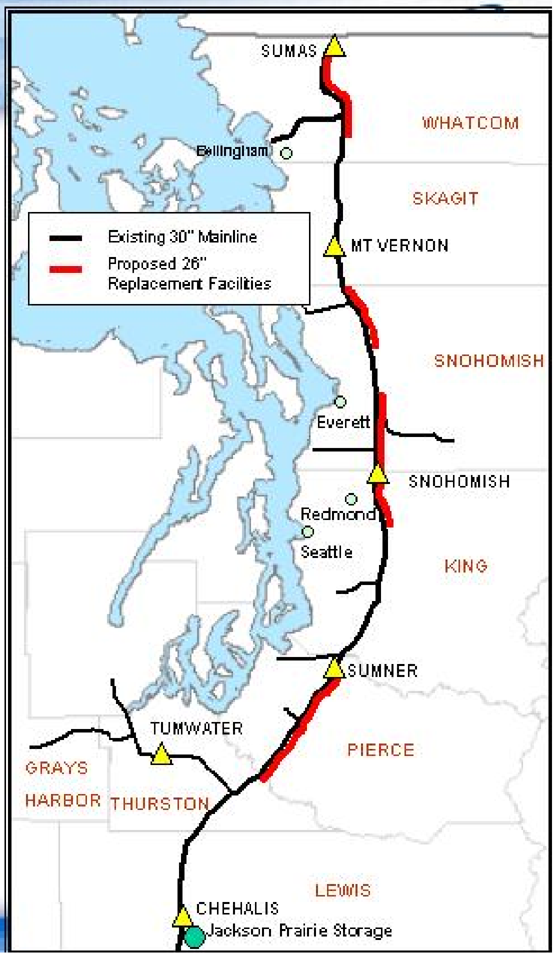
- Northwest
  - Evergreen Expansion placed into service 10/1/03
  - Columbia River Gorge Expansion placed into service 10/21/03
  - Rocky Mountain Expansion Project placed into service 11/30/03
- Transco
  - Trenton-Woodbury Expansion placed into service 11/1/03
  - South Central New Jersey Expansion, open season

Gas Pipeline
Strengths

- Location
- Low cost provider
- Few expiring long-term contracts
- Customer credit quality
- Gas supplies
- System flexibility

Gas Pipeline
Restore/Replace 26"

- Corrective Action Order
  - Idle 26" mainline Sumas, WA to Washougal, WA
  - Allows temporary removal of restrictions after testing
  - Required to replace capacity within 10 years; expect to replace in 3 years
  - Evaluate additional segments
- Cost recoverable through rates



FERC Issues

Williams.

- Future Rate Cases
  - No filing requirement until 2007
  - Transco filing possible pre-2007
  - 26" Restore/Replace triggers Northwest filing
- Energy Affiliate Rule

Gas Pipeline
2004-2006 Guidance

Williams

Dollars in millions	**2004**	**2005**	**2006**
Segment profit	$525-575	$525-575	$525-575
Annual DD&A*	$275-285	$280-290	$290-300
Capital spending			
Expansion:	$30-40	$15-30	$25-40
Non-Exp:	$240-250	$265-280	$165-180
Replacement:	$25-50	$100-120	$240-260
Total	$295-340	$380-430	$430-480

* Legal entity basis

Gas Pipeline
Challenges and Opportunities

- Challenge
  - Restore/replace Northwest's 26" pipeline
- Opportunities
  - Transco rate upside
  - Gulfstream capacity
  - Organic growth over long-term

Midstream

Alan Armstrong, Senior VP


Wyoming
• Produce over 50% of NGL's coming out of Wyoming
San Juan
• Gather approximately 38% of the gas, ranking Midstream #1 in the basin
Gulf Coast
• Gather 40% of the gas produced in the Western Gulf of Mexico
Venezuela
•Gas injections allow PDVSA to freely produce approximately 700,000 BOPD, which is roughly 50% of all crude oil production
Fort McMurray (Oil Sands)
Olefins Fractionator
Straddle Plants
WYOMING
FOUR CORNERS
Conway
GULF COAST
VENEZUELA
Williams

Midstream
Segment Profit

Dollars in millions	**4th Quarter** **2003**	**2002**	**2003**	**2002**
Segment Profit	$46	$(27)	$286	$183
Includes:				
▪ Impairments	42	115	60	123
▪ Gains on sale of assets	(16)	-	(27)	-
▪ Early retirement/realignment	-	-	-	3
Recurring Segment Profit	$72	$88	$319	$309
▪ Operation of Assets sold/To be sold	5	11	9	55
	$67	$77	$310	$254

- 4Q 2002 vs. 4Q 2003
  - Weaker olefins margins
- 2002 vs. 2003
  - Increased Deepwater revenues

Midstream
4Q 2003 Accomplishments

- Strong operating cash flow
- Deepwater expansions
  - Gunnison pipeline in-service
  - Devils Tower spar topsides set
- Asset sales progress
  - NGL Trading & Wholesale Propane - closed 12/03
  - Wilprise equity ownership - closed 10/03
  - Tristates equity ownership - closed 10/03
  - Dry Trail - closed 12/03
  - Satisfactorily re-contracted ethane in Western Canada
- Completed 415 well connect program
- Strong operational metrics

Midstream
Remaining Assets for Sale

Dollars in millions

	Timing of Closing
Cameron Meadows/Black Marlin	2Q04
Gulf Liquids (Disc. Operations)	2Q04
Ethylene Distribution	2Q04
Canadian Straddle Plants	3Q04
Conway	3Q04
South Texas	4Q04
Pre-tax Proceeds	**$500 – 600**

Midstream
2004 – 2006 Guidance

Williams.

Dollars in millions	**2003FC** ***2-20-03***	**2003**	**2004**	**2005**	**2006**
Segment profit	$200-300	$286	$275-375	$300-400	$350-450
Annual DD&A*	$190-200	$199	$180-190	$170-180	$175-185
Capital spending	$250	$263	$90-110	$60-80	$50-70
CFFO	$300-350	$413			

Key Assumptions for Ranges:

- NGL Margins
- Olefins Margins
- Deepwater Growth
- Asset Sales

* 2004-2006 on legal entity basis

Midstream

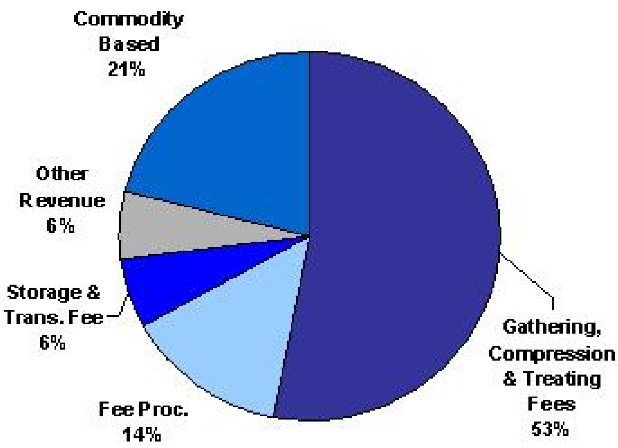
Segment Profit Breakdown-Guidance

Williams

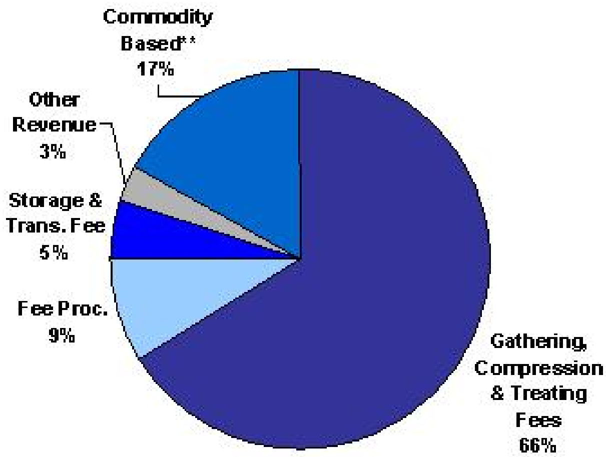
Dollars in millions	2002	2003	2004	2005	2006
G&P	263	315	280-330	320-370	350-420
Segment Profit	263	333	280-330	320-370	350-420
Gains/Losses/Impairments	-	(18)	-	-	-
Petchem Services	(87)	(28)	(20)-30	(20)-30	(20)-30
Segment Profit	(10)	(28)	(20)-30	(20)-30	(20)-30
Gains/Losses/Impairments	(77)	-	-	-	-
Assets Sold/To Be Sold	7	(1)	0-20	-	-
Segment Profit	53	14	0-20	-	-
Gains/Losses/Impairments	(46)	(15)	-	-	-
Total Segment Profit	**$183**	**$286**	**$275-375**	**$300-400**	**$350-450**
Segment Profit plus DD&A	**$364**	**$485**	**$455-565**	**$470-580**	**$525-635**

Note: Sum of ranges for each business line does not necessarily match total range for Midstream segment

Midstream
Net Revenue* Components



End of Year 2003



2006

* Net Revenue is total revenues before eliminations less cost of goods sold for NGLs, Olefins, Condensate, & Trading

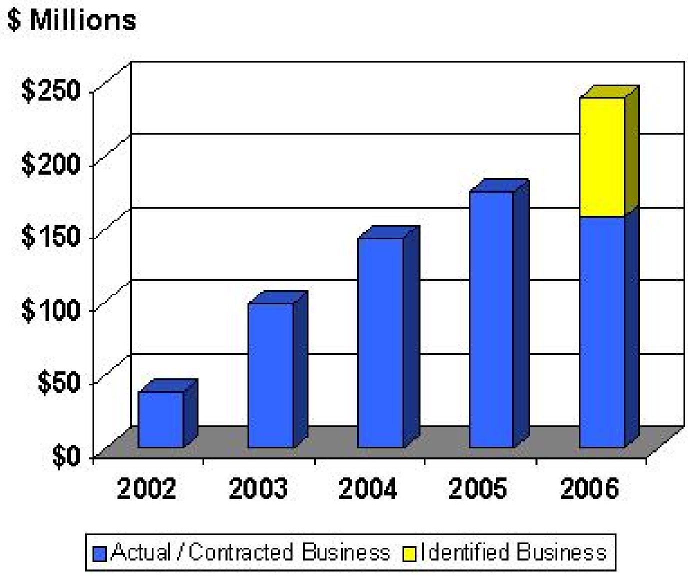
** Reflects 2003 margins

Midstream

Projected Deepwater Growth

- East Breaks
  - Placed in service 4th Qtr. 2001
    - Original Projection for 2003 = 172MMcfd
    - 2003 Actual = 343 MMcfd
- Canyon Station
  - Production exceeding estimates by 30+ MMcfd
- Green Canyon
  - Inception to date production is 15% above original projection
- Devils Tower
  - Spar on location
  - 2Q 2004 start-up
  - Substantial developments in area
- Gunnison
  - 4th Qtr. In-service
  - 2nd 2004 flow = 23 MBPD
  - 2005 flow = 35 MBPD

Segment Profit Before DD&A



Midstream
Challenges / Opportunities

Williams.

Challenges

- Commodity margins
- Deepwater - contract identified business in 2006
- FERC affiliate ruling

Opportunities

- Commodity margins
- Additional Deepwater prospects
- Olefins Margins

Summary

Williams

- 2003 strong financial performance
- Strategy intact
- Maintaining focus on core business in spite of asset sales
  - Success in past, present and future
- Reducing volatility
- Exciting growth opportunities continue to exist
  - Deepwater
  - Core basins

Power

Bill Hobbs, Senior VP

Power
4Q 2003 Segment Profit

Dollars in Millions	4th Quarter 2003	2002	2003	2002
Accrual Earnings (Losses)	($67)	$1	($268)	$11
MTM Earnings (Losses)[1]	73	126	393	(420)
Interest Rate Earnings (Losses)	14	(6)	(12)	91
SG&A	(17)	(29)	(124)	(209)
Operating Expenses & Other Inc (Exp)	(35)	(17)	(79)	(49)
Impairments	(89)	(98)	(89)	(253)
Gain on Sale of Assets	-	-	208	-
Origination	-	-	-	204
Income Related to Prior Periods[2]	-	-	105	-
Segment Profit/(Loss)	**($121)**	**($23)**	**$134**	**($625)**

[1] "MTM Earnings (Losses)" reflects realized and unrealized gains/losses on derivative contracts. Note that change in the fair value of underlying non-derivatives are not included in Segment Profit.

[2] Amount represents correction made to prior period accounting treatment of certain derivative contracts. In addition to the $81 million in revenues disclosed in the second quarter of 2003, approximately $24 million in related revenues were also recognized in 2003 prior to the correction.

Power

Williams

Dollars in millions	4th Quarter			
	2003	2002	2003	2002
Segment Profit/(Loss)	($121)	($23)	$134	($625)
Includes				
▪ Impairments	89	98	89	259
▪ Reduction in Force Costs	-	6	12	13
▪ Income Related to Prior Periods[1]	-	-	(105)	-
▪ Contract Sales/Liquidations [2]	-	-	(208)	-
▪ Cal. Refund & Other Accrual Adj.	33	-	33	-
▪ Regulatory & Other Loss Accruals	-	-	20	-
Recurring Segment Profit/(Loss)	$1	$81	($25)	($353)

[1]Amount represents correction made to prior period accounting treatment of certain derivative contracts. In addition to the $81 million in revenues disclosed in the second quarter of 2003, approximately $24 million in related revenues were also recognized in 2003 prior to the correction.

[2] Includes non-derivatives only.

Power

Undiscounted Cash Flows-Guidance

Williams.

Combined Power Portfolio Estimated as of 12/31/03

Dollars in Millions	**2003**	**2004**	**2005**	**2006**
Tolling Demand Payment Obligations	($393)	($391)	($395)	($400)
Resale of Tolling	123	143	117	104
Full Requirements	19	16	41	46
Long Term Physical Forward Power Sales	75	97	100	76
OTC Hedges	6	168	52	78
Estimated Hedges Tolling Revenues	51	108	196	251
	($119)	$141	$111	$155
Estimated Merchant Revenue Unhedged	$0	$6	$49	$73
Estimated Combined Power Portfolio Cash Flows	($119)	$147	$160	$228
Forecasted SG&A				
Direct	(105)	(50)	(50)	(50)
Allocated	(19)	(25)	(25)	(25)
Estimated Cash Flows after SG&A	**($243)**	**$72**	**$85**	**$153**

Note: Actual cash flows realized upon liquidation or sale of the portfolio may differ materially from those shown.

Power
2003 Cash Flow

Williams

Dollars in millions	Power Only	Other Bus. W/C	Total
Portfolio Cash Flow	($243)	-	($243)
Unusual Items			
Jackson Sale	188	-	188
Allegheny Termination	100	-	100
Deferred Tax Change	220	-	220
Working Capital and Other	231	(337)	(106)
Cash Flows from Operations	$496	($337)	$159

Power

2004-2006 Guidance

Dollars in millions	2004	2005	2006
Segment Profit	$0-150	$50-150	$50-200
Cash Flows from Operations[1]	$150-350	$50-150	$50-200

[1] Power only, excludes all commodity Margin Volatility

Note: Because Power does not currently qualify for Hedge Accounting, actual segment profit may vary significantly from given ranges. Future liquidations, sales or partial sale of the portfolio may result in gains or losses significantly different than ranges given above.

Power
Challenges / Opportunities

Challenges
- Depressed cycle
- Stated intent to exit the business

Opportunities
- Higher spark spreads
- New risk reducing, value enhancing origination deals
- Increased liquidity resulting in additional forward hedging
- Improved credit resulting in reduced prepays for gas
- Favorable resolution of ongoing litigation and investigations

Power
Outlook

- Power markets depressed
  - West has positive exit value
  - Negative exit value for remainder
- Estimated cash flows from hedges cover approximately 98% of demand payment obligations through 2010
- Expect positive cash flows despite depressed markets through 2010
- Opportunities and risks greater after 2010
- Impairments of goodwill and Hazelton plant
- Net book value of portfolio & other long-lived assets in excess of $800 million
- Other net assets (A/R, Margin, etc) total approximately $400 million
- Tolling, full requirements, storage, transportation and transmission contracts represent additional exposure not reflected on balance sheet

2004-2006 Consolidated Outlook

Don Chappel

Consolidated

2004 Segment Profit Guidance

Dollars in millions

	2004 Forecast
Gas Pipeline	$525 - 575
Exploration & Production	275 - 340
Midstream	275 - 375
Other/Rounding	25 - (40)
	$1,100 - 1,250
Power	0 - 150
Total	**$1,100 - 1,400**

Consolidated 2004 Guidance

Williams

Dollars in millions, except per-share amounts	$
Segment profit*	**$1,100 - $1,400**
EBITDA	**1,600 - 2,000**
Cash Flow from Operations	**1,000 - 1,300**
Income from continuing operations	**20 - 200**
Net Income	**0 - 200**
Diluted Earnings Per Share	**$0.00 - $0.40**

Note: Excludes potential gains, losses and impairments

2004 Forecast
EBITDA Reconciliation

Williams

	Dollars in millions
Net Income	$0 - 200
Income from Disc. Operations	0 - 20
Net Interest	810 - 900
DD&A	650 - 700
Provision for Income Taxes	80 - 175
Other/Rounding	60 - 5
EBITDA	**$1,600 – 2,000**

Consolidated
2004 Forecast Segment Contribution

	Gas Pipes	E&P	Midstream	Power	Corp/Other	Total
Segment Profit (Loss)	525 - 575	275 - 340	275 - 375	0 - 150	25 – (40)	1,100 - 1,400
DD&A*	275 - 285	160 - 180	180 - 190	20 - 25	15 - 20	650 - 700
Segment Profit before DDA	800 - 860	435 - 520	455 - 565	20 - 175	40 - (20)	1,750 - 2,100
General Corporate Expense						(130) – (110)
Investing Income						0 - 50
Other/Rounding						(20) – (40)
TOTAL						1,600 – 2,000

* Legal entity basis

Consolidated
2004 - 2006 Outlook

Dollars in millions

	2004	2005	2006
Segment Profit	1,100 - 1,400	1,300 - 1,600	1,400 - 1,700
DD&A	650 - 700	650 - 750	700 - 800
Cash flow from Operations	1,000 - 1,300	1,300 - 1,600	1,400 - 1,700
Capital Expenditures	700 - 800	900 - 1,100	900 - 1,100
Effective Tax Rate*	39%	39%	39%

* An additional $25 million income tax expense is forecast each year

Consolidated Drivers

Williams

Dollars in millions	Segment Profit		CFFO	
	Low	**High**	**Low**	**High**
2003	**1,350**	**1,650**	**600**	**800**
Interest savings	-	-	340	400
Gains on Asset Sales	(236)	(236)	-	-
Other	(14)	(14)	60	100
2004	**1,100**	**1,400**	**1,000**	**1,300**
Interest savings	-	-	50	200
E&P improvements	75	110	150	200
Other	125	90	100	(100)
2005	**1,300**	**1,600**	**1,300**	**1,600**
Interest savings	-	-	20	70
E&P improvements	50	50	75	90
Other	50	50	5	(60)
2006	**1,400**	**1,700**	**1,400**	**1,700**

Financial Strategy

- Maintain a cash/liquidity cushion of $1.0 billion plus
- Complete new bank credit facilities
- Continue to de-lever - striving for investment grade ratios
- Uses of excess cash
  - Pay scheduled debt retirements
  - Early debt reduction
  - Disciplined EVA® -based investment
  - Consider dividend and/or share repurchase policy upon achieving investment grade

Summary

Steve Malcolm

Strategy

Commercial

- Natural gas assets in key growth markets where we enjoy the competitive advantages of scale, low-cost position and market leadership

Financial

- Create and maintain adequate liquidity from all available sources to fully support business strategy
- De-leverage through combination of asset sales, refinancing, cost-cutting
- Develop balance sheet capable of supporting and ultimately growing business and value

Business Unit Positioning

- Exploration & Production
  - Generates free cash flow, primary growth driver
- Midstream
  - Generates free cash flow, decreasing volatility, growth in Deepwater
- Gas Pipeline
  - Generates free cash flow, steady contributor
- Power
  - Exit business
  - Reduce risk and volatility

A Work in Progress

Williams

Initiate & Stabilize → Execute Restructuring → Emerge

Measures of Success

Initiate & Stabilize	Execute Restructuring	Emerge
☑ Avoid bankruptcy	☑ Complete asset sales	☑ Position company for integrated natural gas growth
☑ Address liquidity crisis	☑ Rationalize cost structure	☐ Optimize capital structure
☑ Restore customer and supplier confidence	☑ Manage liquidity	☐ Capitalize on strategic position
	☑ De-lever	
	☑ Restore confidence of and gain access to capital markets	

Appendix

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Williams

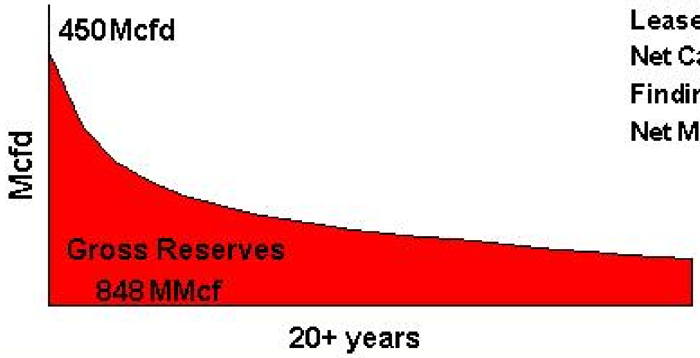
Average 2004 Lona Valley Well

Finding Costs

Drill & Complete	$375,000
Total Development Cost	$375,000
Reserves, Mcf	678,473
Drilling cost	$0.55

Illustrative Economics

NYMEX Gas Price (MMbtu)	$4.92
Basis adjustment	-0.20
Midcon. Gas Price (per MMbtu)	$4.72
BTU Adjustment - 993 MMbtu/Mcf	0.00
Fuel & Shrink - 8.0%	-0.38
Gathering/Treating/Compression	-0.21
Net Realized Price - Mcf	$4.13
Production Taxes - 7.0%	-0.29
Lease Op Exp - $2,500/well/month	-0.58
Net Cash Flow - Mcf	$3.26
Finding & Development Cost	-0.55
Net Margin	$2.71
IRR (after-tax)	73%



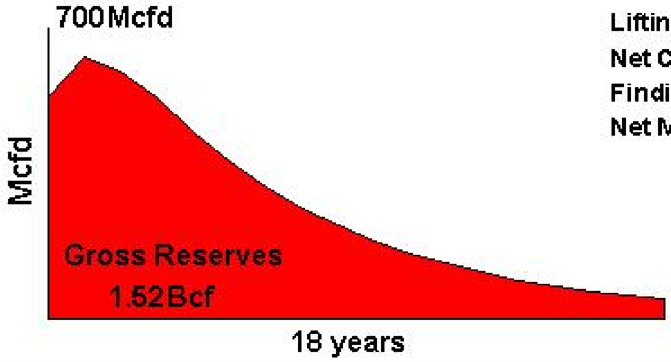
Average 2004 Fruitland Coal Well

Finding Costs

Drill & Complete	$583,000
Total Development Cost	$583,000
Reserves, Mcf	1,327,512
Drilling Cost	$0.44

Illustrative Economics

NYMEX Gas Price (MMbtu)	$4.92
Basis Adjustment	-0.42
San Juan Gas Price (per MMbtu)	$4.50
BTU Adjustment - 990 MMbtu/Mcf	-0.04
Fuel & Shrink - 5.7%	-0.26
Gathering/Treating/Compression	-0.42
Net Realized Price - Mcf	$3.78
Production Taxes	-0.34
Water disposal fee - $2.50/bbl	-0.63
Lifting Cost - $3,500/well/month	-0.39
Net Cash Flow - Mcf	$2.42
Finding & Development Cost	-0.44
Net Margin	$1.98
IRR (after-tax)	67%



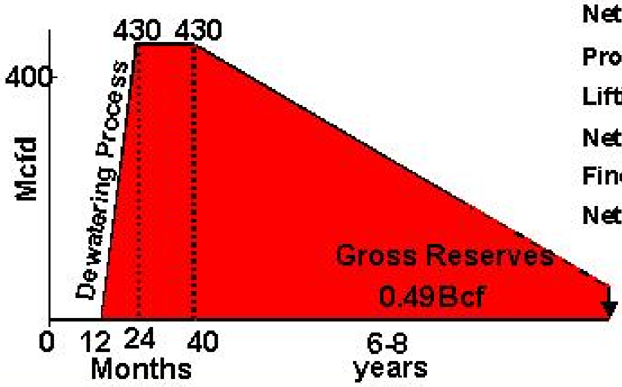
Average 2004 Big George Coal Well

Finding Costs

D & C	$120,000
Hook-up	$25,000
Total Well Cost	$145,000
Net Reserves, Mcf	415,567
Drilling Cost	$0.35

Illustrative Economics

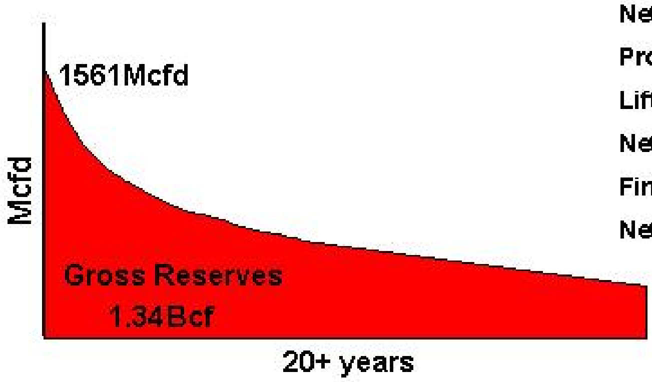
NYMEX Gas Price (MMbtu)	$4.92
Basis Adjustment (to Glenrock)	-0.57
Rocky Mountain Gas Price (per MMbtu)	$4.35
BTU Adjustment - 940 MMbtu/Mcf	-0.26
Fuel Shrinkage - 7%	-0.30
Transportation/Gathering/Compression	-0.50
Net Realized Gas Price - Mcf	$3.29
Production taxes	-0.46
Lifting Costs - $875/well/month	-0.24
Net Cash Flow - Mcf	$2.59
Finding & Development Cost	-0.35
Net Margin	$2.24
IRR (after-tax)	57%



Average 2004 Mesaverde Well

Finding Costs

D & C	$1,030,000
Total Well Cost, $	$1,030,000
Net Reserves, Mcf	1,102,329
Drilling Cost	$0.93



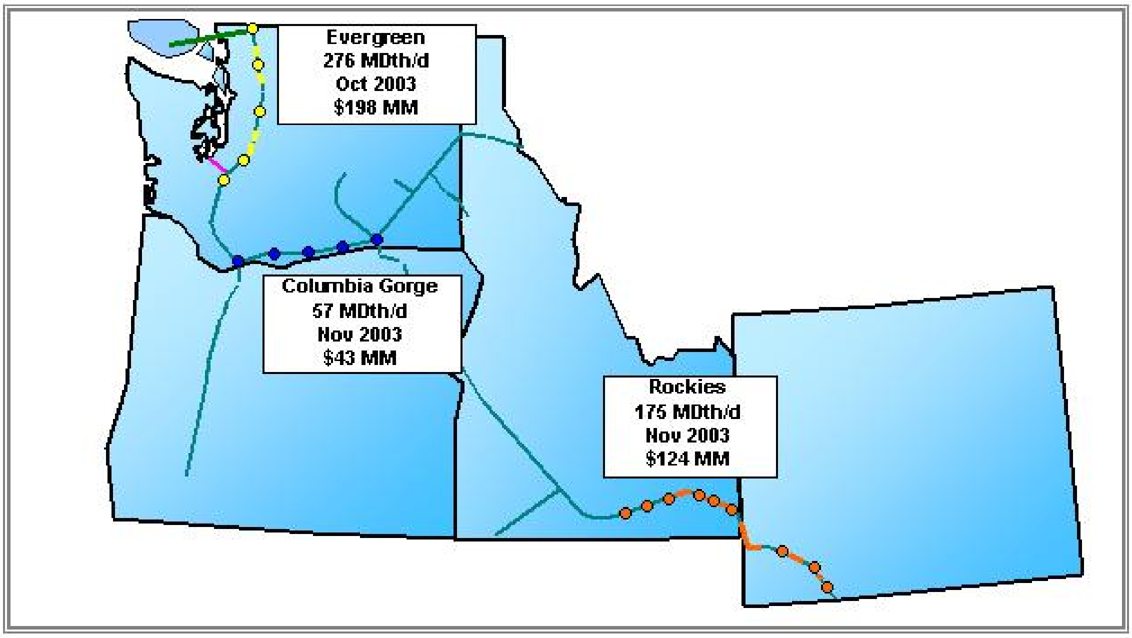
Illustrative Economics

NYMEX Gas Price (MMbtu)	$4.92
Basis Adjustment	-0.55
Basin Gas Price (per MMbtu)	$4.37
BTU Adjustment - 1080 MMbtu/Mcf	+0.35
Gathering/Compression (GVGS)	-0.13
Net Realized Gas Price - Mcf	$4.59
Production taxes	-0.31
Lifting Costs - $650/well/month	-0.17
Net Cash Flow - Mcf	$4.11
Finding & Development Cost	-0.93
Net Margin	$3.18
IRR (after-tax)	56%

Gas Pipeline

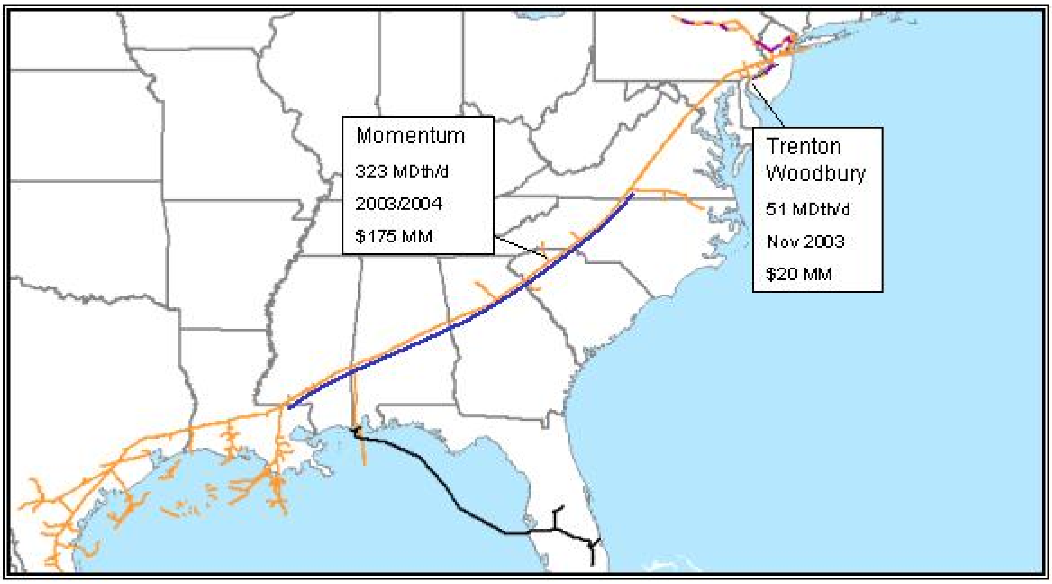
Northwest 2003 Expansion Projects

Williams.



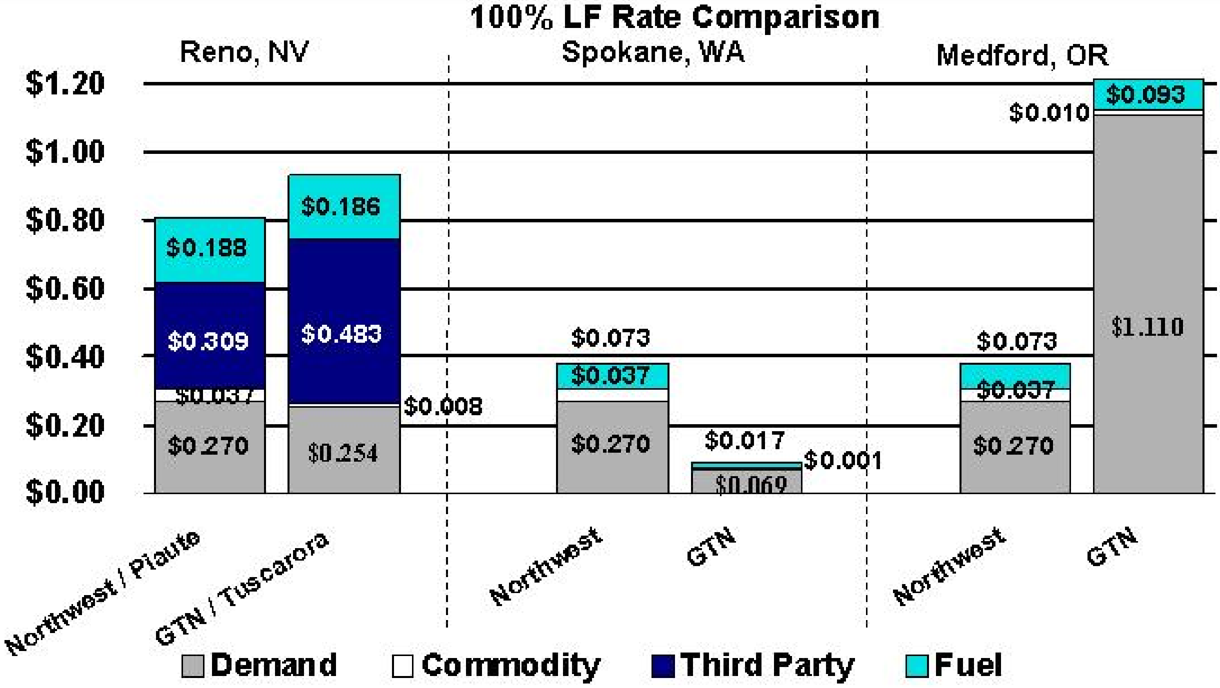
Gas Pipeline
Transco 2003/2004 Expansion Projects

Williams



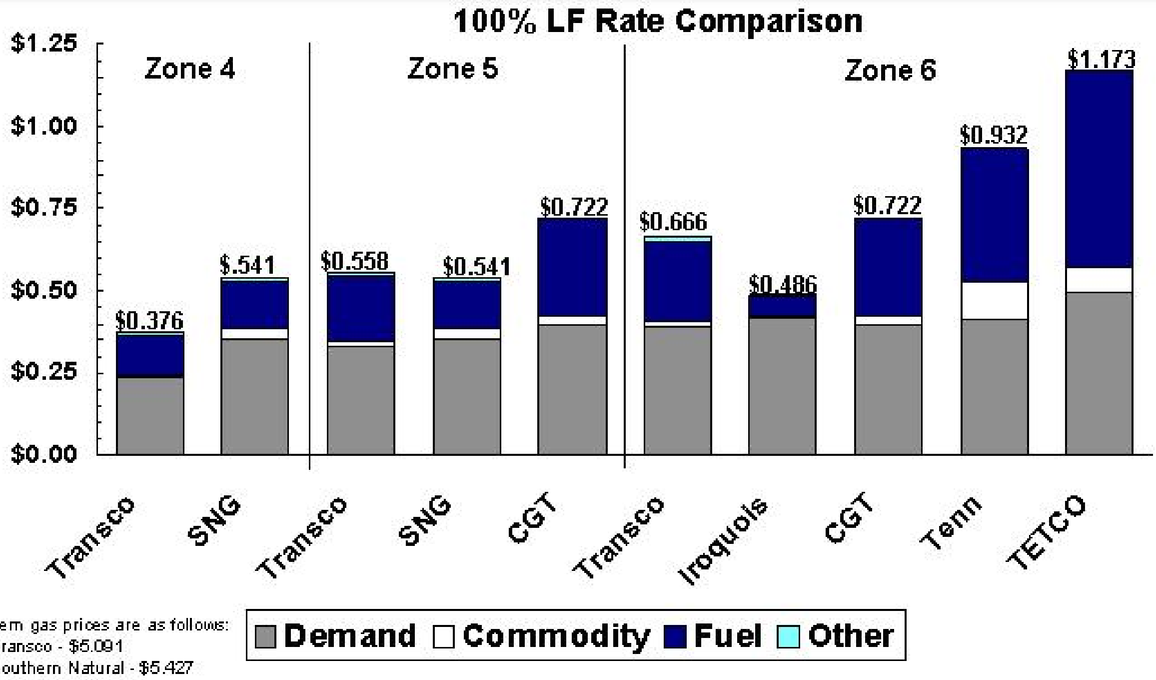
Gulfstream 2004 Extension Project

Gas Pipeline
Northwest Rate Comparison



System gas prices are as follows:
Northwest Blended - $4.61
GTN - $4.57

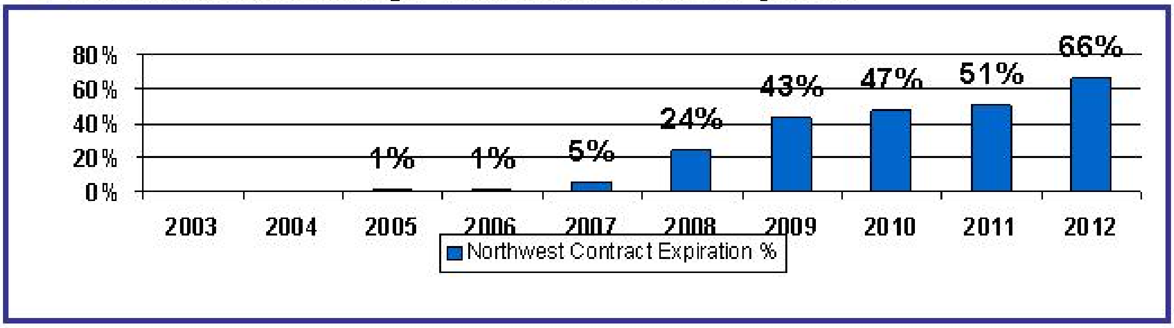
Gas Pipeline
Transco Rate Comparison



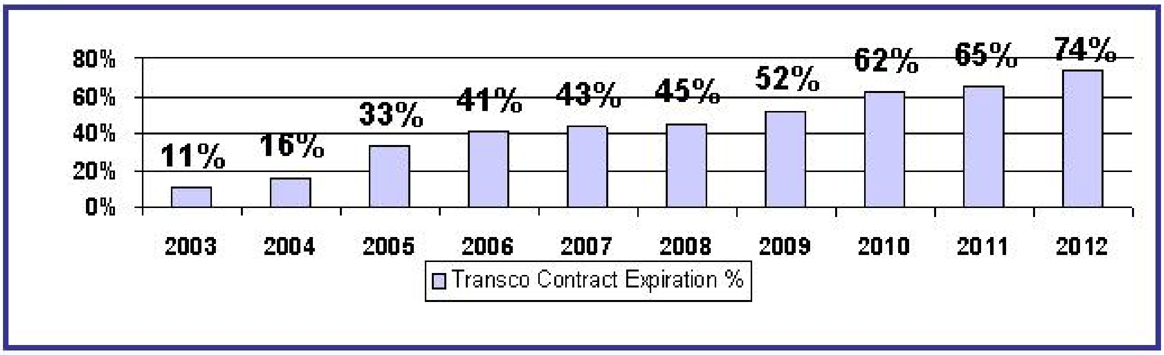
System gas prices are as follows:
- Transco - $5.091
- Southern Natural - $5.427
- Columbia – $5.498
- Iroquois - $6.375
- Tennessee - $5.382
- Texas Eastern - $5.435

Gas Pipeline
Contract Expirations – Cumulative

- Northwest's average contract life is 8.7 years



- Transco's average contract life is 5.8 years



Gas Pipeline
Northwest Customer Base

Company	Credit Rating	2003 Revenue ($MM)	Customer Type
Puget Sound Energy, Inc.	BBB-/Baa3	$ 49	Local Distribution Co.
Northwest Natural Gas Co.	A-/A3	38	Local Distribution Co.
Duke Energy	BBB-	34	Marketer
Pan-Alberta Gas (U.S.) Inc.	Guaranty	26	Producer / Aggregator
IGI Resources Inc.	Gty/AA+	19	Marketer
Cascade Natural Gas Corp.	BBB+/Baa1	14	Local Distribution Co.
Avista Corp.	BB+/Ba1	13	Local Distribution Co.
Intermountain Gas Co.	Private Company	12	Local Distribution Co.
Portland General Electric	BBB+/Baa3	8	Electric Utility
Sierra Pacific Power Co.	B+/B2	7	Local Distribution Co.

Gas Pipeline
Transco Customer Base

Company	Credit Rating	2003 Revenue ($MM)	Customer Type
PSEG Energy Resources	Baa1/BBB	$115	Local Distribution Co.
KeyspanGas East	A3	86	Local Distribution Co.
Piedmont Natural Gas Co.	A3/A	74	Local Distribution Co.
ConEdof NY	A1/A	51	Local Distribution Co.
SCANA	A3/A	46	Local Distribution Co.
Williams EM&T	B3/B+	34	Marketer
Philadelphia Gas Works	Baa2	30	Local Distribution Co.
South Jersey Gas Company	Baa2/BBB+	22	Local Distribution Co.
Atlanta Gas Light	A3/A-	21	Local Distribution Co.
Washington Gas Light Co.	AA-/A2	21	Local Distribution Co.

Gas Pipeline

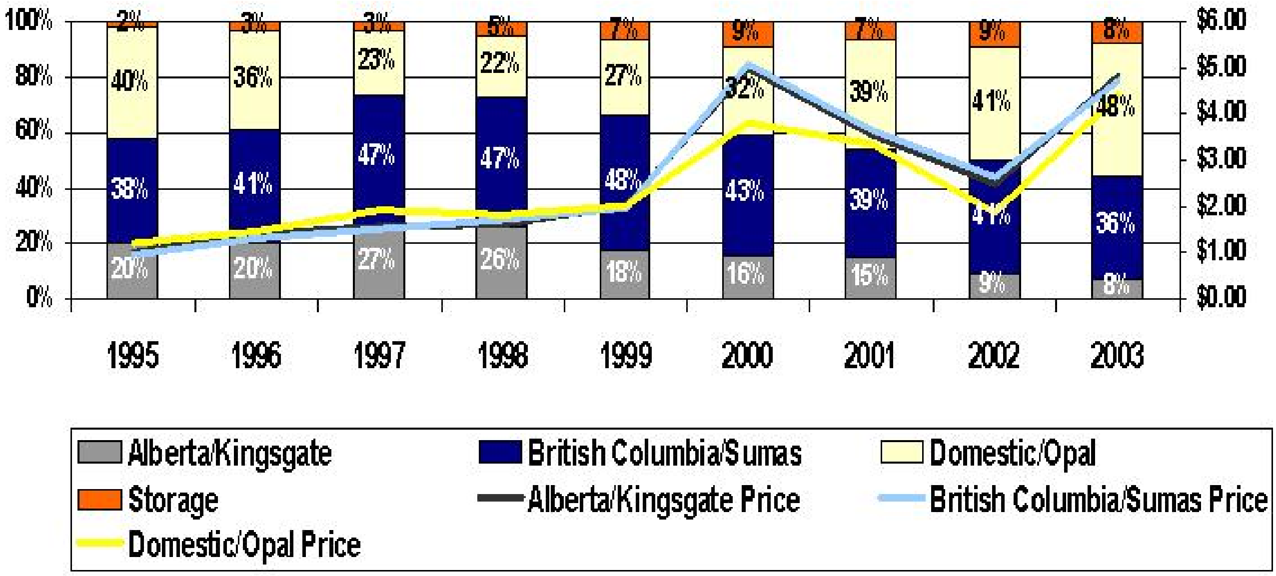
Gulfstream Customer Base

- Contract terms are for 18 – 23 years

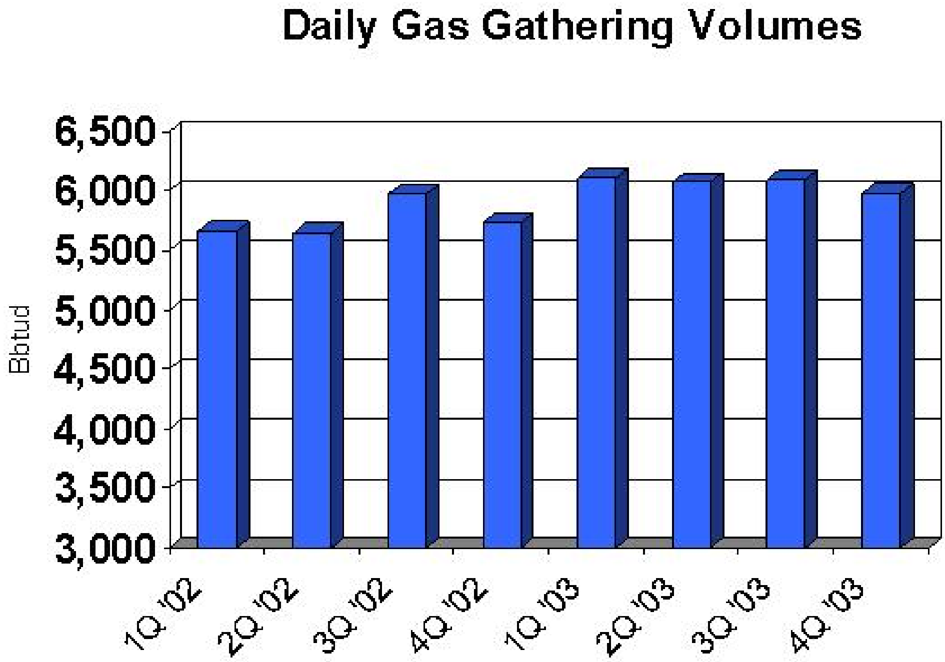
Company	FT Contract Mdth/d	Demand Revenue ($MM)	Rating	Primary Company Type
PHASE I (May 2002)				
Seminole	**32**	**$6.4**	**A**	**IOU**
Lakeland	**30**	**$6.0**	**AAA/A1**	**IOU**
FPC	**190**	**$38.0**	**BBB/A2**	**IOU**
Central FL Gas	**10**	**$2.0**	**BBB+**	**LDC**
Peoples Gas	**35**	**$7.0**	**BBB-/Baa2**	**LDC**
FMPA	**10**	**$2.0**	**A3**	**Muni. Utility**
Calpine	**68**	**$13.7**	**CCC+/Caa1**	**IPP**
PHASE II (Dec 2004)				
FPL	**350**	**$70.3**	**BBB/A1**	**IOU**

Note: Revenue is an estimated first full year using the negotiated rates.

Northwest Supply Diversity



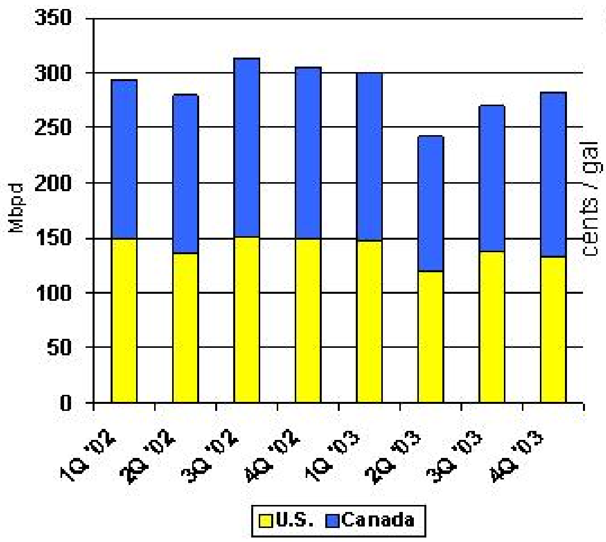
Midstream
2003 Strong Operational Metrics



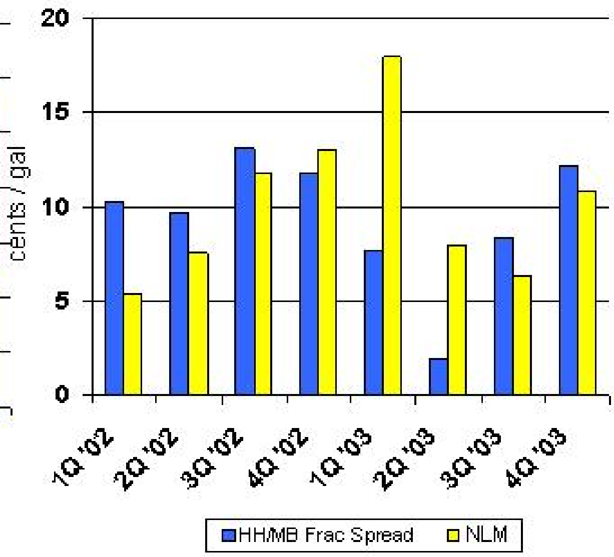
Midstream
2003 Strong Operational Metrics

Williams.

Total NGL Production



Frac Spread vs. Net Liquid Margin



Power

Physical Natural Gas

- Average annual requirements
  - 2.7 Bcf/d with peak of 3.5 Bcf/d
    - 48% for Power
      - 20% power-plant supply
      - 28% third-party transactions
    - 52% for Williams' core businesses
- Transportation
  - 2.5 Bcf/d
    - 35% for Power
    - 65% for Williams' core businesses
- Storage
  - 21 Bcf
    - 67% for Power
    - 33% for Williams' core businesses
- Improving market liquidity and credit

Total Undiscounted Cash Flows

($ Millions)

Combined Power Portfolio *Estimated as of 12/31/03*	2003	2004	2005	2006	2007-2010	2011-2022
Tolling Demand Payment Originations	(393)	(391)	(395)	(400)	(1,630)	(3,839)
Resale of Tolling	123	143	117	104	279	0
Full Requirements	19	16	41	46	153	153
Long-term Physical Forward Power Sales	75	97	100	76	155	0
OTC Hedges	6	168	52	78	6	(4)
Estimated Hedged Tolling Revenues	51	108	196	251	555	446
Subtotal	(119)	141	111	155	(482)	(3,244)
Estimated Merchant Revenue Unhedged	0	6	49	73	1,181	5,650
Est. Combined Power Portfolio Cash Flows	(119)	147	160	228	699	2,406
Forecasted Direct SG&A	(105)	(50)	(50)	(50)	(200)	(500)
Forecasted Indirect SG&A	(19)	(25)	(25)	(25)	(100)	(300)
Estimated Cash Flows After SG&A	(243)	72	85	153	399	1,606

West Undiscounted Cash Flows

($ Millions)

West Power Portfolio *Estimated as of 12/31/03*	**2003**	**2004**	**2005**	**2006**	**2007-2010**	**2011-2022**
Tolling Demand Payment Originations	(151)	(153)	(154)	(156)	(639)	(1,240)
Resale of Tolling	123	143	117	104	279	0
Long-term Physical Forward Power Sales	73	104	98	76	155	0
OTC Hedges	(79)	81	27	48	7	(3)
Estimated Hedged Tolling Revenues	49	72	115	150	322	134
Subtotal	15	247	203	222	124	(1,109)
Estimated Merchant Revenue Unhedged	0	6	41	46	617	2,353
Estimated Cash Flows - West Power Portfolio	15	253	244	268	741	1,244

Mid. Cont. Undiscounted Cash Flows

($ Millions)

Mid-Continent Power Portfolio

Estimated as of 12/31/03	2003	2004	2005	2006	2007-2010	2011-2022
Tolling Demand Payment Originations	(87)	(88)	(89)	(89)	(365)	(844)
Long-term Physical Forward Power Sales	1	(7)	2	0	0	0
OTC Hedges	28	34	(6)	(8)	(8)	0
Estimated Hedged Tolling Revenues	(13)	7	24	24	52	109
Subtotal	(71)	(54)	(69)	(73)	(321)	(735)
Estimated Merchant Revenue Unhedged	0	0	4	19	228	888
Estimated Cash Flows - MidCon Power Portfolio	(71)	(54)	(65)	(54)	(93)	153

East Undiscounted Cash Flows

($ Millions)

East Power Portfolio *Estimated as of 12/31/03*	**2003**	**2004**	**2005**	**2006**	**2007-2010**	**2011-2022**
Tolling Demand Payment Originations	(155)	(150)	(152)	(154)	(626)	(1,755)
Full Requirements	19	16	41	46	153	153
OTC Hedges	57	54	32	38	7	(2)
Estimated Hedged Tolling Revenues	16	28	56	76	181	204
Subtotal	(63)	(52)	(23)	6	(285)	(1,400)
Estimated Merchant Revenue Unhedged	0	0	4	8	336	2,409
Estimated Cash Flows - East Power Portfolio	(63)	(52)	(19)	14	51	1,009

Consolidated
Scheduled Debt Maturities

($ Millions)

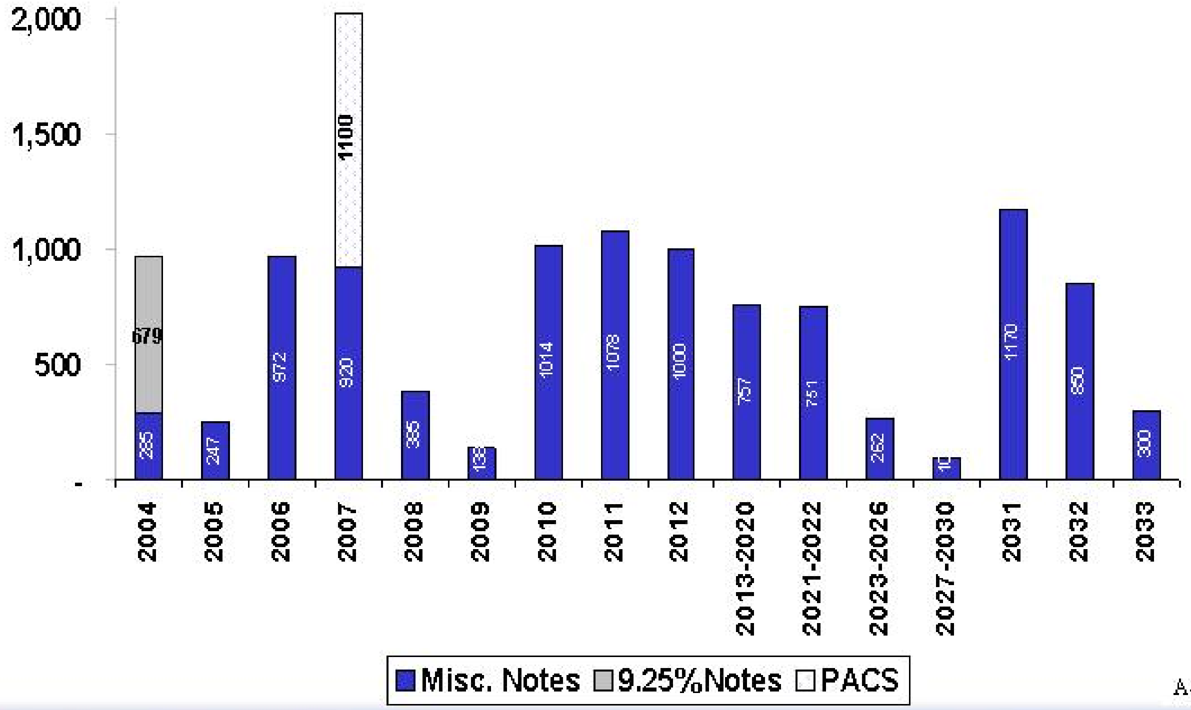


Exhibit 99.2

NewsRelease

NYSE: WMB

Date: Feb. 19, 2004

Williams Reports Unaudited 2003 Financial Results and Outlook

• *2003 Net Loss Includes Cumulative Effect of EITF Issue No. 02-3*

• *Company Committed to Continued Debt Reduction, Disciplined Growth*

TULSA, Okla. – Williams (NYSE:WMB) today announced an unaudited 2003 net loss of $504.5 million, or a loss of $1.03 per share on a diluted basis, compared with a net loss of $754.7 million, or a loss of $1.63 per share, for the same period in 2002.

During the first quarter of 2003, the company recorded an after-tax charge of $761.3 million, or $1.47 per share, to reflect the cumulative effect of new accounting principles primarily associated with the adoption of Emerging Issues Task Force (EITF) Issue 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities."

The company reported 2003 income from continuing operations of $2.9 million. This resulted in a loss of 5 cents per share on a diluted basis, which includes the effect of preferred stock dividends. In the same period for 2002, the company reported a loss of $611.7 million, or a loss of $1.35 per share, on a basis restated for discontinued operations related to assets sold or held for sale.

Factors in the improved full-year performance from continuing operations include a $759 million improvement in Power segment profit, significantly reduced levels of asset and investment impairment charges, reduced losses associated with interest-rate swaps, and lower general corporate expenses.

Income from discontinued operations for 2003 was $253.9 million, or 49 cents per share, compared with a loss from discontinued operations of $143 million, or a loss of 28 cents per share, in 2002 on a restated basis. The year-over-year improvement from discontinued operations largely reflects net gains from asset sales in 2003.

For the fourth quarter of 2003, the company reported a net loss of $66 million, or a loss of 13 cents per share, compared with a net loss of $219.2 million, or a loss of 44 cents per share for the same period of 2002. Included in the fourth quarter of 2003 is $66.8 million of pre-tax expense associated with the early retirement of debt.

"The improvement in our results is indicative of the significant steps we've taken to restructure our company," said Steve Malcolm, chairman, president and chief executive officer. "In 2003, we made substantial progress in strengthening our finances, we refocused our business strategy around key natural gas assets, and we began executing on a plan toward achieving investment-grade credit characteristics. That plan includes making continued disciplined capital investments to grow our businesses."

Recurring Results

Recurring income from continuing operations – which excludes items of income or loss that the company characterizes as unrepresentative of its ongoing operations – was $12 million, or 2 cents per share, for 2003. In 2002, the recurring results from continuing operations reflected a loss of $221.7 million on a restated basis, or a loss of 43 cents per share.

A reconciliation of the company's income from continuing operations – a generally accepted accounting principles measure – to its recurring results accompanies this news release.

Core-Business Performance

Williams' natural gas businesses – Gas Pipeline, Exploration & Production and Midstream Gas & Liquids – reported combined segment profit of $1.24 billion in 2003 vs. the same level in 2002 on a restated basis.

These businesses, which the company considers core to its strategy, reported combined segment profit of $244.4 million in the fourth quarter of 2003 vs. $176.6 million for the same period in 2002. The fourth-quarter results included $41.7 million and $115 million of impairments in 2003 and 2002, respectively, related to certain Midstream assets.

"Our natural gas wells, pipelines and midstream assets are producing the solid results that we expected in what was a challenging environment of liquidity-driven divestitures and constrained capital investment," said Malcolm. "While we are focusing the majority of our available cash toward debt reduction, we are once again making disciplined investments in these world-class assets to create economic value. In the near-term, we are focused on maintaining or improving our favorable market position so that we create opportunities for more substantial growth in the future."

Gas Pipeline, which provides natural gas transportation and storage services, reported 2003 segment profit of $554.9 million vs. $545.1 million for the previous year on a restated basis.

Results reflect the benefit of expansion projects that are now in service and reduced general and administrative costs, offset by lower equity earnings and a $25.5 million charge at Northwest Pipeline to write-off capitalized software development costs associated with a cancelled service delivery system. Equity earnings in 2002 included a $27.4 million benefit related to a construction fee received by an affiliate and $19 million of equity earnings from an investment that was sold in the fourth quarter of 2002.

For the fourth quarter of 2003, Gas Pipeline reported segment profit of $148.4 million, compared with restated segment profit of $122.1 million for 2002. The quarter-over-quarter increase was due to completed expansion projects and the absence of a $17 million FERC-related charge in 2002.

Exploration & Production, which includes natural gas production and development in the U.S. Rocky Mountains, San Juan Basin and Midcontinent, reported 2003 segment profit of $401.4 million vs. $508.6 million for the previous year on a restated basis.

Year-over-year results reflect the impact of lower levels of production in 2003 due to property sales and reduced drilling activities in the first half of the year, and reduced gains from the sales of assets in 2003 vs. 2002 of approximately $46 million.

For the fourth quarter of 2003, segment profit was $50.1 million, compared with $81.5 million a year ago on a restated basis. The quarter-over-quarter decline in segment profit reflects the impact of lower net domestic production volumes resulting from previous property sales.

Midstream Gas & Liquids, which provides gathering, processing, natural gas liquids fractionation and storage services, reported 2003 segment profit of $286 million vs. a restated segment profit of $183.2 million for the previous year.

The increase in segment profit reflects a net reduction of $73 million for impairment charges recorded in 2003 vs. 2002 associated with certain Canadian assets, the contribution of increased operations in the deepwater area of the Gulf of Mexico and gains on the sales of certain assets and investments. Partially offsetting these items were lower margins in the Canadian and U.S.-based olefins business and $14.1 million of impairment charges associated with the Aux Sable equity interest.

For the fourth quarter of 2003, segment profit was $45.9 million vs. a segment loss of $27 million on a restated basis in the same period a year ago. The increase in segment profit is primarily a result of $73 million in lower impairment charges associated with the Canadian operations. In addition, the current quarter includes a gain of $16.2 million from the sale of Williams' wholesale propane business.

Power Business

Power, which manages more than 7,500 megawatts of power through long-term contracts, reported 2003 segment profit of $134.2 million vs. a segment loss of $624.8 million for the previous year.

The company is pursuing a strategy designed to result in substantially exiting the power business through sales of component parts of its portfolio or as a whole.

As Williams has previously stated, the exact timing of that exit and the resulting value to the company are uncertain because of the complexity of the underlying contracts and a power market that is significantly depressed based on historical comparisons. In the interim, Williams' strategy is to manage this business – which continues to play a significant role in the company's financial performance – to reduce risk, generate cash and honor contractual obligations.

Consistent with the overarching and interim strategies described above, Williams received $315 million in cash in 2003 from sales of and agreements to terminate certain contracts.

The significant improvement in Power's year-over-year performance reflects gains on the sales of assets, contracts and investments of $208 million, as well as significantly reduced levels of impairments in 2003 from those of 2002. As previously disclosed, Power recognized $80.7 million of revenue in the second quarter of 2003 from a correction of the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001. Results for 2003 include $105 million of revenue related to these prior period items, of which $24 million was recorded prior to the correction.

The 2003 results also include the application of a different accounting treatment (EITF Issue No. 02-3), under which non-derivative, energy-related trading contracts are accounted for on an accrual basis. In 2002, all energy-related contracts, including tolling and full-requirements contracts, were marked to market. In 2003, Power recognized gains on power and natural gas derivative contracts, while 2002 reflected significant mark-to-market losses.

For the fourth quarter of 2003, Power reported a segment loss of $121.3 million, compared with a loss of $22.8 million in 2002. The fourth quarter of 2003 includes asset and goodwill impairment charges totaling $89.1 million and a charge of $33.3 million related to refund and other accrual adjustments for power marketing activities in California during 2000 and 2001. The prior year quarter included $95.5 million of impairment charges related to assets that were disposed.

Other

In the **Other** segment, the company reported a segment loss of $50.5 million in 2003 vs. a restated segment profit of $14.1 million for the previous year. The decrease in 2003 primarily results from an impairment of the company’s investment in a petroleum pipeline project.

For the fourth quarter of 2003, Williams reported a segment loss of $7.7 million, compared with a restated segment loss of $20.8 million for 2002.

Changes in Cash and Debt

For 2003, Williams increased its unrestricted cash by $665.3 million, ending the year with available cash and equivalents of approximately $2.3 billion.

A significant factor in the company’s increased cash is approximately $3 billion in net proceeds from asset sales and $315 million from the sale and/or agreement to terminate certain marketing and trading contracts in 2003.

Williams also reduced its debt by approximately $2 billion during 2003, including debt associated with discontinued operations and the early retirement of approximately $951 million of debt through tender offers.

Net cash provided by operating activities was approximately $770 million in 2003. In 2002, the company’s operating activities used approximately $515 million in cash.

Williams has already completed the majority of its planned asset sales. The company continues to market certain Midstream assets in 2004, such as its straddle plants in Western Canada. Williams also expects to complete the sale of its Alaska operations in the first quarter.

Company Direction for 2004

“The progress we’ve made toward strengthening our finances since this time last year defines the kind of discipline we will continue to exercise this year and in the years ahead,” Malcolm said.

Consistent with the company's stated financial and commercial strategies, Williams in 2004 will continue to focus on disciplined growth, cash management and cost efficiencies. Capital allocation will be assessed using Economic Value Added® financial metrics, adopted Jan. 1.

Growth plans call for 1,400 new natural gas wells in 2004, the construction of a previously announced 110-mile expansion of the Gulfstream Natural Gas System and the spring startup of Midstream's Devils Tower floating production system in the deepwater Gulf of Mexico.

On March 15, Williams is scheduled to retire the remaining $679 million of 9.25 percent Notes. Beyond March 15, Williams has $505 million of scheduled debt maturities for 2004 and 2005.

Williams plans to capitalize on its financial flexibility by establishing new credit facilities at favorable terms that reduce cash-on-hand requirements. The company's goal is to maintain liquidity of approximately $1 billion to $1.3 billion.

Earnings Guidance

Williams is providing updated forecasts for 2004 through 2006 during a presentation this morning to analysts.

In 2004, Williams expects enterprise-wide segment profit of $1.1 billion to $1.4 billion. In 2005, Williams expects enterprise-wide segment profit of $1.3 billion to $1.6 billion. In 2006, Williams expects enterprise-wide segment profit of $1.4 billion to $1.7 billion.

Information on how to access the presentation and the analyst call via the company's web site is provided at the end of this news release.

Analyst Call

Williams' management will discuss the company's year-end 2003 financial results during an analyst presentation to be webcast live at 10 a.m. Eastern today.

Participants are encouraged to access the presentation and corresponding slides via www.williams.com. A limited number of phone lines also will be available at (800) 810-0924. International callers should dial (913) 981-4900. Callers should dial in at least 10 minutes prior to the start of the discussion.

A webcast replay of the presentation will be archived at www.williams.com later today in the section for investors. An audio replay of the presentation also will be available at 3 p.m. Eastern today through midnight Eastern on Feb. 26. To access the audio replay, dial (888) 203-1112. International callers should dial (719) 457-0820. The replay confirmation code is 608313.

Form 10-K

The company plans to file its Form 10-K with the Securities and Exchange Commission in early March. 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. Williams' gas wells, pipelines and midstream facilities are concentrated in the Northwest, Rocky Mountains, Gulf Coast and Eastern Seaboard. More information is available at www.williams.com.

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

Financial Highlights
(UNAUDITED)

(Millions, except per-share amounts)	Three months ended December 31,				Years ended December 31,			
	2003		**2002***		**2003**		**2002***	
Revenues	**$**	**3,529.3**	$	1,122.1	**$**	**16,814.2**	$	3,716.6
Income (loss) from continuing operations	**$**	**(96.8)**	$	(151.2)	**$**	**2.9**	$	(611.7)
Income (loss) from discontinued operations	**$**	**30.8**	$	(68.0)	**$**	**253.9**	$	(143.0)
Cumulative effect of change in accounting principles	**$**	**—**	$	—	**$**	**(761.3)**	$	—
Net loss	**$**	**(66.0)**	$	(219.2)	**$**	**(504.5)**	$	(754.7)
Basic and diluted earnings (loss) per common share:								
Loss from continuing operations	**$**	**(.19)**	$	(.31)	**$**	**(.05)**	$	(1.35)
Income (loss) from discontinued operations	**$**	**.06**	$	(.13)	**$**	**.49**	$	(.28)
Cumulative effect of change in accounting principles	**$**	**—**	$	—	**$**	**(1.47)**	$	—
Net loss	**$**	**(.13)**	$	(.44)	**$**	**(1.03)**	$	(1.63)
Average shares (thousands)		**518,502**		517,104		**518,137**		516,793
Shares outstanding at December 31 (thousands)						**518,232**		516,731

* Amounts have been restated as described in Note 1 of Notes to Consolidated Statement of Operations.

Consolidated Statement of Operations
(UNAUDITED)

		Three months ended December 31,		Years ended December 31,	
(Millions, except per-share amounts)		**2003**	**2002***	**2003**	**2002***
REVENUES	Power	**$ 2,565.5**	$ 130.1	**$ 13,175.6**	$ 56.2
	Gas Pipeline	**347.1**	322.3	**1,299.0**	1,241.8
	Exploration & Production	**166.9**	208.2	**779.7**	860.4
	Midstream Gas & Liquids	**833.6**	428.8	**3,319.2**	1,525.2
	Other	**12.9**	45.4	**72.0**	124.1
	Intercompany eliminations	**(396.7)**	(12.7)	**(1,831.3)**	(91.1)
	Total revenues	**3,529.3**	1,122.1	**16,814.2**	3,716.6
SEGMENT COSTS AND EXPENSES	Costs and operating expenses	**3,183.7**	624.2	**15,156.8**	2,218.6
	Selling, general and administrative expenses	**90.6**	116.0	**412.2**	568.7
	Other (income) expense — net	**160.6**	239.7	**(88.7)**	276.8
	Total segment costs and expenses	**3,434.9**	979.9	**15,480.3**	3,064.1
	General corporate expenses	**24.5**	26.4	**87.0**	142.8
OPERATING INCOME	Power	**(130.5)**	(13.6)	**125.4**	(471.7)
	Gas Pipeline	**142.4**	115.4	**539.0**	470.6
	Exploration & Production	**48.3**	79.9	**392.5**	504.9
	Midstream Gas & Liquids	**40.2**	(32.1)	**285.7**	165.6
	Other	**(6.0)**	(7.4)	**(8.7)**	(16.9)
	General corporate expenses	**(24.5)**	(26.4)	**(87.0)**	(142.8)
	Total operating income	**69.9**	115.8	**1,246.9**	509.7
	Interest accrued	**(251.3)**	(360.4)	**(1,286.4)**	(1,159.6)
	Interest capitalized	**10.9**	9.0	**45.5**	27.3
	Interest rate swap income (loss)	**4.2**	1.0	**(2.2)**	(124.2)
	Investing income (loss)	**29.6**	9.8	**73.4**	(113.1)
	Minority interest in income and preferred returns of consolidated subsidiaries	**(4.3)**	(6.1)	**(19.4)**	(41.8)
	Other income (expense) — net	**(65.8)**	5.3	**(26.1)**	24.3
	Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	**(206.8)**	(225.6)	**31.7**	(877.4)
	Provision (benefit) for income taxes	**(110.0)**	(74.4)	**28.8**	(265.7)
	Income (loss) from continuing operations	**(96.8)**	(151.2)	**2.9**	(611.7)
	Income (loss) from discontinued operations	**30.8**	(68.0)	**253.9**	(143.0)
	Income (loss) before cumulative effect of change in accounting principles	**(66.0)**	(219.2)	**256.8**	(754.7)
	Cumulative effect of change in accounting principles	**—**	—	**(761.3)**	—
	Net loss	**(66.0)**	(219.2)	**(504.5)**	(754.7)
	Preferred stock dividends	**—**	6.8	**29.5**	90.1
	Loss applicable to common stock	**$ (66.0)**	$ (226.0)	**$ (534.0)**	$ (844.8)
EARNINGS (LOSS) PER SHARE	Basic and diluted earnings (loss) per common share:				
	Loss from continuing operations	**$ (.19)**	$ (.31)	**$ (.05)**	$ (1.35)
	Income (loss) from discontinued operations	**.06**	(.13)	**.49**	(.28)
	Income (loss) before cumulative effect of change in accounting principles	**(.13)**	(.44)	**.44**	(1.63)
	Cumulative effect of change in accounting principles	**—**	—	**(1.47)**	—
	Net loss	**$ (.13)**	$ (.44)	**$ (1.03)**	$ (1.63)

* Certain amounts have been restated or reclassified as described in Note 1 of Notes to Consolidated Statement of Operations.

See accompanying notes.

1. BASIS OF PRESENTATION

Discontinued operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standard (SFAS) No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” the results of operations for the following components have been reflected in the Consolidated Statement of Operations as discontinued operations (see Note 6):

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream Gas & Liquids segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream Gas & Liquids segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline’s segments;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- Central natural gas pipeline, previously one of Gas Pipeline’s segments;
- two natural gas liquids pipeline systems, Mid-American Pipeline and Seminole Pipeline, previously part of the Midstream Gas & Liquids segment; and
- Kern River Gas Transmission (Kern River), previously one of Gas Pipeline’s segments.

Unless indicated otherwise, the information in the Notes to the Consolidated Statement of Operations relates to our continuing operations. We expect that other components of our business may be classified as discontinued operations in the future as the sales of those assets occur.

As previously disclosed, Power recognized $80.7 million of revenue in the second quarter of 2003 from a correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. Results for 2003 include $105 million of revenue related to these prior period items, of which $24 million was recorded prior to the correction. Management, after consultation with its independent auditor, concluded that the effect of the previous accounting treatment was not material to prior periods, 2003 results and trend of earnings.

2. SEGMENT REVENUES AND PROFIT (LOSS)

We currently evaluate performance based on segment profit (loss) from operations, which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on impairments related to investments accounted for under the equity method. Equity earnings (losses) and income (loss) from investments are reported in investing income (loss) in the Consolidated Statement of Operations.

During third-quarter 2003, we announced the name change of Energy Marketing & Trading to Power. Our management believes the new name more accurately reflects the emphasis of the segment’s current business activity.

Power has entered into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power’s segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of parent company interest rate swaps with external counterparties are shown as interest rate swap income (loss) in the Consolidated Statement of Operations below operating income.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties.

2. SEGMENT REVENUES AND PROFIT (LOSS) (continued)

(Millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Three months ended December 31, 2003							
Segment revenues:							
External	**$ 2,364.3**	**$ 344.7**	**$ (8.8)**	**$ 826.0**	**$ 3.1**	**$ —**	**$ 3,529.3**
Internal	**210.9**	**2.4**	**175.7**	**7.6**	**9.8**	**(406.4)**	**—**
Total segment revenues	**2,575.2**	**347.1**	**166.9**	**833.6**	**12.9**	**(406.4)**	**3,529.3**
Less intercompany interest rate swap income	**9.7**	**—**	**—**	**—**	**—**	**(9.7)**	**—**
Total revenues	**$ 2,565.5**	**$ 347.1**	**$ 166.9**	**$ 833.6**	**$ 12.9**	**$ (396.7)**	**$ 3,529.3**
Segment profit (loss)	**$ (121.3)**	**$ 148.4**	**$ 50.1**	**$ 45.9**	**$ (7.7)**	**$ —**	**$ 115.4**
Less:							
Equity earnings (losses)	**—**	**6.0**	**1.8**	**1.4**	**(1.1)**	**—**	**8.1**
Income (loss) from investments	**(.5)**	**—**	**—**	**4.3**	**(.6)**	**—**	**3.2**
Intercompany interest rate swap income	**9.7**	**—**	**—**	**—**	**—**	**—**	**9.7**
Segment operating income (loss)	**$ (130.5)**	**$ 142.4**	**$ 48.3**	**$ 40.2**	**$ (6.0)**	**$ —**	**94.4**
General corporate expenses							**(24.5)**
Consolidated operating income							**$ 69.9**
Three months ended December 31, 2002							
Segment revenues:							
External	$ 338.1	$ 313.2	$ 4.2	$ 432.7	$ 33.9	$ —	$ 1,122.1
Internal	(209.5)*	9.1	204.0	(3.9)	11.5	(11.2)	—
Total segment revenues	128.6	322.3	208.2	428.8	45.4	(11.2)	1,122.1
Less intercompany interest rate swap loss	(1.5)	—	—	—	—	1.5	—
Total revenues	$ 130.1	$ 322.3	$ 208.2	$ 428.8	$ 45.4	$ (12.7)	$ 1,122.1
Segment profit (loss)	$ (22.8)	$ 122.1	$ 81.5	$ (27.0)	$ (20.8)	$ —	$ 133.0
Less:							
Equity earnings (losses)	(5.7)	5.6	1.6	5.1	(13.6)	—	(7.0)
Income (loss) from investments	(2.0)	1.1	—	—	.2	—	(.7)
Intercompany interest rate swap loss	(1.5)	—	—	—	—	—	(1.5)
Segment operating income (loss)	$ (13.6)	$ 115.4	$ 79.9	$ (32.1)	$ (7.4)	$ —	142.2
General corporate expenses							(26.4)
Consolidated operating income							$ 115.8

* Prior to January 1, 2003, Power intercompany cost of sales, which are netted in revenues consistent with fair-value accounting, exceed intercompany revenue. Beginning January 1, 2003, Power intercompany cost of sales are no longer netted in revenues due to the adoption of EITF Issue No. 02-3. Segment revenues and profit for Power include net realized and unrealized mark-to-market gains of $84.6 million from derivative contracts accounted for on a fair value basis for the three months ended December 31, 2003.

2. SEGMENT REVENUES AND PROFIT (LOSS) (continued)

(Millions)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
Year ended December 31, 2003							
Segment revenues:							
External	**$ 12,268.6**	**$ 1,275.0**	**$ (36.3)**	**$ 3,274.6**	**$ 32.3**	**$ —**	**$ 16,814.2**
Internal	**904.1**	**24.0**	**816.0**	**44.6**	**39.7**	**(1,828.4)**	**—**
Total segment revenues	**13,172.7**	**1,299.0**	**779.7**	**3,319.2**	**72.0**	**(1,828.4)**	**16,814.2**
Less intercompany interest rate swap loss	**(2.9)**	**—**	**—**	**—**	**—**	**2.9**	**—**
Total revenues	**$ 13,175.6**	**$ 1,299.0**	**$ 779.7**	**$ 3,319.2**	**$ 72.0**	**$ (1,831.3)**	**$ 16,814.2**
Segment profit (loss)	**$ 134.2**	**$ 554.9**	**$ 401.4**	**$ 286.0**	**$ (50.5)**	**$ —**	**$ 1,326.0**
Less:							
Equity earnings (losses)	**—**	**15.8**	**8.9**	**(5.7)**	**1.3**	**—**	**20.3**
Income (loss) from investments	**11.7**	**.1**	**—**	**6.0**	**(43.1)**	**—**	**(25.3)**
Intercompany interest rate swap loss	**(2.9)**	**—**	**—**	**—**	**—**	**—**	**(2.9)**
Segment operating income (loss)	**$ 125.4**	**$ 539.0**	**$ 392.5**	**$ 285.7**	**$ (8.7)**	**$ —**	**1,333.9**
General corporate expenses							**(87.0)**
Consolidated operating income							**$ 1,246.9**
Year ended December 31, 2002							
Segment revenues:							
External	$ 909.6	$ 1,184.7	$ 62.6	$ 1,492.8	$ 66.9	$ —	$ 3,716.6
Internal	(994.8)*	57.1	797.8	32.4	57.2	50.3	—
Total segment revenues	(85.2)	1,241.8	860.4	1,525.2	124.1	50.3	3,716.6
Less intercompany interest rate swap loss	(141.4)	—	—	—	—	141.4	—
Total revenues	$ 56.2	$ 1,241.8	$ 860.4	$ 1,525.2	$ 124.1	$ (91.1)	$ 3,716.6
Segment profit (loss)	$ (624.8)	$ 545.1	$ 508.6	$ 183.2	$ 14.1	$ —	$ 626.2
Less:							
Equity earnings (losses)	(9.7)	88.4	3.7	17.6	(27.0)	—	73.0
Income (loss) from investments	(2.0)	(13.9)	—	—	58.0	—	42.1
Intercompany interest rate swap loss	(141.4)	—	—	—	—	—	(141.4)
Segment operating income (loss)	$ (471.7)	$ 470.6	$ 504.9	$ 165.6	$ (16.9)	$ —	652.5
General corporate expenses							(142.8)
Consolidated operating income							$ 509.7

* Prior to January 1, 2003, Power intercompany cost of sales, which are netted in revenues consistent with fair-value accounting, exceed intercompany revenue. Beginning January 1, 2003, Power intercompany cost of sales are no longer netted in revenues due to the adoption of EITF Issue No. 02-3. Segment revenues and profit for Power include net realized and unrealized mark-to-market gains of $388.9 million from derivative contracts accounted for on a fair value basis for the year ended December 31, 2003.

3. ASSET SALES, IMPAIRMENTS AND OTHER ACCRUALS

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense – net within segment costs and expenses for the three months and the years ended December 31, 2003 and 2002, are as follows:

	(Income) Expense			
	Three months ended December 31,		Years ended December 31,	
(millions)	2003	2002	2003	2002
Power				
Gain on sale of Jackson power contract	$ —	$ —	$ (188.0)	$ —
Commodity Futures Trading Commission settlement	—	—	20.0	—
Guarantee loss accruals and write-offs	—	(6.2)	—	56.2
Impairment of goodwill	45.0	3.6	45.0	61.1
Impairment of generation facilities	44.1	44.7	44.1	44.7
Loss accruals and impairment of other power related assets	—	50.8	—	82.6
California rate refund and other accrual adjustments	19.5	—	19.5	—
Gas Pipeline				
Write-off of software development costs due to cancelled implementation	—	—	25.6	—
Exploration & Production				
Net gain on sale of certain natural gas properties	(.3)	2.2	(96.7)	(141.7)
Midstream Gas & Liquids				
Gain on sale of the wholesale propane business	(16.2)	—	(16.2)	—
Impairment of Canadian assets	41.7	115.0	41.7	115.0

Power

In June 2002, we announced our intent to exit the Power business. As a result, Power pursued efforts to sell all or portions of our power, natural gas, and crude and refined products portfolios in the latter half of 2002 and in 2003. Based on bids received in these sales efforts, we impaired certain assets and projects in 2002. We also sold or terminated energy contracts for less than their carrying value, which resulted in significant 2002 losses. During 2003, we continued our focus on exiting the Power business and, as a result, impaired certain assets.

Guarantee loss accruals and write-offs. The 2002 guarantee loss accruals and write-offs within Power of $56.2 million includes accruals for commitments for certain assets that were previously planned to be used in power projects, write-offs associated with a terminated power plant project and a $13.2 million reversal of loss accruals related to the wind-down of our mezzanine lending business.

Goodwill. The fair value of the Power reporting unit used to calculate the goodwill impairment loss in 2002 was based on the estimated fair value of the trading portfolio inclusive of the fair value of contracts with affiliates. In 2002, the trading portfolio was reflected at fair value in the financial statements and the affiliate contracts were not. The fair value of the affiliate contracts was estimated using a discounted cash flow model with natural gas pricing assumptions based on current market information.

During 2003, we continued to focus on exiting the Power business. Because of this and the current market conditions in which this business operates, we evaluated Power's remaining goodwill for impairment. In estimating the fair value of the Power reporting unit, we considered our derivative portfolio which is carried at fair value on the balance sheet and our non-derivative portfolio which is no longer carried at fair value on the balance sheet. Because of the significant negative fair value of certain of our non-derivative contracts, we may be unable to realize our carrying value of this reporting unit. As a result, we recognized an impairment of the remaining goodwill within Power during 2003.

Generation facilities. The 2003 impairment relates to the Hazelton generation facility. Fair value was estimated using future cash flows based on current market information and discounted at a risk adjusted rate. The 2002 impairment was of the Worthington generation facility. Fair value was estimated based on expected proceeds from the sale of the facility, which closed in first-quarter 2003.

Loss accruals and impairment of other power related assets. The 2002 loss accruals and impairments of other power related assets were recorded pursuant to reducing activities associated with the distributive power generation business.

California rate refund and other accrual adjustments. In addition to the $19.5 million charge included in other (income) expense — net within segment costs and expenses, a $13.8 million charge is recorded within costs and operating expenses. These two amounts, totaling $33.3 million are for California rate refund and other accrual adjustments and relate to power marketing activities in California during 2000 and 2001.

Midstream Gas & Liquids

Canadian assets. Approximately $38 million of the 2002 Canadian asset impairment reflects a reduction of carrying cost to management's estimate of fair market value for our natural gas liquid extraction plants, determined primarily from information available from efforts to sell these assets in a single transaction. The balance is associated with an olefin fractionation facility whose carrying costs were determined to be not fully recoverable. Fair value was estimated using discounted future cash flows.

During 2003, efforts to sell the natural gas liquid extraction plants were temporarily suspended and these assets were reevaluated individually. This resulted in an additional impairment of certain of the natural gas liquid extraction plants to fair value. We estimated fair value using an earnings multiple applied to projected 2005 earnings. This estimate was validated by a range of discounted future cash flows for the assets.

4. INVESTING INCOME (LOSS)

Investing income (loss) for the three months and the years ended December 31, 2003 and 2002, is as follows:

(millions)	Three months ended December 31, 2003	Three months ended December 31, 2002	Years ended December 31, 2003	Years ended December 31, 2002
Equity earnings (losses)*	**$ 8.1**	$ (7.0)	**$ 20.3**	$ 73.0
Income (loss) from investments*	**3.2**	(.7)	**(25.3)**	42.1
Impairments of cost based investments	**(.4)**	.3	**(35.0)**	(12.1)
Loss provision for WilTel receivables	**—**	1.2	**—**	(268.7)
Interest income and other	**18.7**	16.0	**113.4**	52.6
Total	**$ 29.6**	$ 9.8	**$ 73.4**	$ (113.1)

* Item also included in segment profit.

Equity earnings for the year ended December 31, 2002, include a benefit of $27.4 million for a contractual construction completion fee received by one of our equity affiliates whose operations are accounted for under the equity method of accounting. This equity affiliate served as the general contractor on the Gulfstream pipeline project for Gulfstream Natural Gas System (Gulfstream), an interstate natural gas pipeline subject to FERC regulations and an equity affiliate of ours. The fee paid by Gulfstream was for the early completion during second-quarter 2002 of the construction of Gulfstream's pipeline. It was capitalized by Gulfstream as property, plant and equipment and is included in Gulfstream's rate base to be recovered in future revenues.

Income (loss) from investments for the year ended December 31, 2003, includes:

- $43.1 million impairment of our investment in equity and debt securities of Longhorn Partners Pipeline L.P., which is included in the Other segment;
- $14.1 million impairment of our equity interest in Aux Sable, which is included in the Midstream Gas & Liquids segment;
- $13.5 million gain on the sale of stock in eSpeed Inc., which is included in the Power segment; and
- $11.1 million gain on sale of our equity interest in West Texas LPG Pipeline, L.P. which is included in the Midstream Gas & Liquids segment.

Income (loss) from investments for the year ended December 31, 2002, includes:

- $58.5 million gain on sale of our investment in AB Mazeikiu Nafta, a Lithuanian oil refinery, pipeline and terminal complex, which was included in the Other segment;
- $12.3 million write-off of Gas Pipeline's investment in a pipeline project which was cancelled in 2002;
- $10.4 million net write-down pursuant to the sale of our equity interest in Alliance Pipeline, a Canadian and U.S. gas pipeline, which was included in the Gas Pipeline segment; and
- $8.7 million gain on sale of our general partner equity interest in Northern Border Partners, L.P., which was included in the Gas Pipeline segment.

Impairments of cost based investments for the years ended December 31, 2003 and 2002, primarily include impairments of various international investments.

5. EARLY RETIREMENT OF DEBT

Other income (expense) — net, below operating income, for the quarter and year-ended December 31, 2003 includes $66.8 million of costs for the early retirement of debt. These costs include payments in excess of the carrying value of the debt, dealer fees and the write-off of deferred debt issuance costs and discount/premium on the debt. Approximately $721 million of senior unsecured 9.25 percent notes and approximately $230 million of other notes and debentures were prepaid as a result of these tender offers.

6. DISCONTINUED OPERATIONS

During 2002, we began the process of selling assets and/or businesses to address liquidity issues. The businesses discussed below represent components that have been sold or approved for sale by our board of directors as of December 31, 2003; therefore, their results of operations (including any impairments, gains or losses) have been reflected in the consolidated financial statement of operations as discontinued operations.

Summarized results of discontinued operations

Summarized results of discontinued operations for the years ended December 31, 2003 and 2002 are as follows:

	Three months ended December 31,		Years ended December 31,	
(millions)	**2003**	**2002**	**2003**	**2002**
Revenues	**$ 253.6**	$ 1,435.4	**$ 2,431.5**	$ 5,685.0
Income from discontinued operations before income taxes	**$ 25.4**	80.8	**$ 150.1**	314.3
(Impairments) and gain (loss) on sales-net	**22.8**	(190.4)	**210.7**	(531.0)
Benefit (provision) for income taxes	**(17.4)**	41.6	**(106.9)**	73.7
Total income (loss) from discontinued operations	**$ 30.8**	$ (68.0)	**$ 253.9**	$ (143.0)

Held for sale at December 31, 2003

Alaska refining, retail and pipeline operations

On November 17, 2003, we entered into agreements to sell our Alaska refinery, retail and pipeline assets for approximately $265 million in cash, subject to various closing adjustments. The transactions are expected to close in the first quarter of 2004 following the completion of various closing conditions.

Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. As a result, impairment charges of $8 million and $18.4 million were recorded during 2003 and 2002, respectively. These impairments are included in the preceding table. These operations were part of the previously reported Petroleum Services segment.

Gulf Liquids New River Project LLC

During second-quarter 2003, our board of directors approved a plan authorizing management to negotiate and facilitate a sale of these assets. Impairment charges totaling $108.7 million were recognized during 2003 to reduce the carrying cost of the long-lived assets to estimated fair value less costs to sell the assets, and are included in the preceding table. Fair value was estimated based on a probability-weighted analysis of various scenarios including expected sales prices, salvage valuations and discounted cash flows. The sale of these operations is expected to be completed within one year of the board's approval. These operations are part of our Midstream Gas & Liquids segment.

2003 Completed transactions

Canadian liquids operations

During 2003, we completed the sale of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. We recognized pre-tax gains totaling $92.1 million in 2003 on the sales which are included in the preceding table. These operations were part of our Midstream Gas & Liquids segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. The December 31, 2002 carrying value reflected the then estimated fair value less cost to sell. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, additional impairment charges of $17.4 million were recognized in 2003. We recognized a loss on the sale of $4.2 million. These impairments, the loss on the sale and $133.5 million of 2002 impairments are included in the preceding table. The soda ash operations were part of the previously reported International segment.

6. DISCONTINUED OPERATIONS (continued)

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional proceeds of $20 million following the occurrence of a contingent event. We recognized a pre-tax gain of $310.8 million on the sale, which is included in the preceding table. We deferred an additional $113 million associated with our indemnifications of the purchasers for a variety of matters, including obligations that may arise associated with existing environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for $59 million in cash. The December 31, 2002 carrying value reflected the estimated fair value less cost to sell. During 2003, we recognized an additional pre-tax loss on the sale of $5.4 million. Impairment charges totaling $195.7 million, including $23 million related to goodwill, were recorded during December 31, 2002, to reduce the carrying cost to our estimate of fair value at that time. Both the additional loss and impairment charges are included in the preceding table. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment of the Anadarko Basin in southwestern Kansas. This sale included all of our interests within these basins. A $39.7 million gain on the sale was recognized during 2003 and is included in the preceding table. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. A $109 million impairment charge was recorded in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on an assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in the preceding table. No significant gain or loss was recognized on the subsequent sale. Texas Gas was a segment within Gas Pipeline.

Midsouth refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee for $455 million in cash. These assets were previously written down by $240.8 million to their estimated fair value less cost to sell at December 31, 2002. A pre-tax gain on sale of $4.7 million was recognized in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million pre-tax gain on the sale of an earn-out agreement that we retained in the sale of the refinery. The 2002 impairment charge and subsequent gains are included in the preceding table. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of the travel centers for approximately $189 million in cash. These assets were previously written down by $146.6 million to their estimated fair value less cost to sell at December 31, 2002. This impairment is included in the preceding table. No significant gain or loss was recognized on the sale. These operations were part of the previously reported Petroleum Services segment.

2002 Completed transactions

Central

On November 15, 2002, we completed the sale of our Central natural gas pipeline for $380 million in cash and the assumption by the purchaser of $175 million in debt. Impairment charges totaling $91.3 million during 2002 are included in the preceding table. Central was a segment within Gas Pipeline.

Mid-America and Seminole Pipelines

On August 1, 2002, we completed the sale of our 98 percent interest in Mid-America Pipeline and 98 percent of our 80 percent ownership interest in Seminole Pipeline for $1.2 billion. The sale generated net cash proceeds of $1.15 billion. The preceding table includes a pre-tax gain of $301.7 million during 2002 and a $11.4 million reduction of the gain during 2003. These assets were part of the Midstream Gas & Liquids segment.

6. DISCONTINUED OPERATIONS (continued)

Kern River

On March 27, 2002, we completed the sale of our Kern River pipeline for $450 million in cash and the assumption by the purchaser of $510 million in debt. As part of the agreement, $32.5 million of the purchase price was contingent upon Kern River receiving a certificate from the FERC to construct and operate a future expansion. This certificate was received in July 2002, and the contingent payment plus interest was recognized as income from discontinued operations in third-quarter 2002. Included in the preceding table is a pre-tax loss of $6.4 million for the year ended December 31, 2002. Kern River was a segment within Gas Pipeline.

7. CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES

The Financial Accounting Standards Board (FASB) issued SFAS No. 143, “Accounting for Asset Retirement Obligations.” This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.” The Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002 with the impact of adoption to be reported as a cumulative effect of change in accounting principle.

We adopted the new rules on asset retirement obligations on January 1, 2003. As required by the new rules, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. The obligations related to producing wells, offshore platforms and underground storage caverns. The liabilities are partially offset by increases in net assets, net of accumulated depreciation, recorded as if the provisions of the Statement had been in effect at the date the obligation was incurred. As a result of the adoption of SFAS No. 143, we recorded a long-term liability of $33.4 million; property, plant and equipment, net of accumulated depreciation, of $24.8 million and a credit to earnings of $1.2 million (net of $.1 million benefit for income taxes). We also recorded a $9.7million regulatory asset for retirement costs expected to be recovered through regulated rates. In connection with adoption of SFAS No. 143, we changed our method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the amounts discussed above.

On October 25, 2002, the EITF reached a consensus on Issue No. 02-3, “Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” This Issue rescinds EITF Issue No. 98-10, the impact of which is to preclude fair value accounting for energy trading contracts that are not derivatives pursuant to SFAS No. 133 and commodity trading inventories. The EITF also reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The consensus is applicable for fiscal periods beginning after December 15, 2002, except for physical trading commodity inventories purchased after October 25, 2002 which may not be reported at fair value. We initially applied the consensus effective January 1, 2003 and reported the initial application as a cumulative effect of a change in accounting principle. The effect of initially applying the consensus reduced net income by approximately $762.5 million on an after tax basis. Physical trading commodity inventories at December 31, 2003 that were purchased prior to October 25, 2002 were reported at fair value at December 31, 2003 and included in the effect of initially applying the consensus. The change results primarily from power tolling load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value. These contracts will be accounted for under an accrual model. Physical trading commodity inventories will be stated at cost, not to be in excess of market.

8. PREFERRED STOCK

Concurrent with the sale of Kern River to MidAmerican Energy Holdings Company (MEHC) on March 27, 2002, we issued approximately 1.5 million shares of 9 7/8 percent cumulative convertible preferred stock to MEHC for $275 million. The terms of the preferred stock allowed the holder to convert, at any time, one share of preferred stock into 10 shares of our common stock at $18.75 per share. Preferred shares had a liquidation preference equal to the stated value of $187.50 per share plus any dividends accumulated and unpaid. Dividends on the preferred stock were payable quarterly. At the time the preferred stock was issued, the conversion price was less than the market price of our common stock and thus deemed beneficial to the purchaser. Proper accounting treatment required that the benefit be recorded as a noncash dividend of $69.4 million, which was a reduction to our retained earnings. An offset to this amount was recorded as an increase to capital in excess of par value.

On June 10, 2003, Williams redeemed all of the outstanding 9 7/8 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends. These shares were repurchased with proceeds from a private placement of 5.5 percent junior subordinated convertible debentures due 2033. Preferred stock dividends for the year ended December 31, 2003 include a $13.8 million premium representing the excess of the purchase price over the carrying value of the shares.

Exhibit 99.3

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

(UNAUDITED)

(Dollars in millions, except for per-share amounts)	2002					2003				
	1st Qtr(1)	2nd Qtr(1)	3rd Qtr(1)	4th Qtr(1)	Year(1)	1st Qtr(1)	2nd Qtr(1)	3rd Qtr	4th Qtr	Year
Income (loss) from continuing operations(2)	$ 46.5	($335.8)	($171.2)	($151.2)	($611.7)	($39.3)	$ 116.2	$ 22.8	($96.8)	$ 2.9
Preferred stock dividends	69.7	6.8	6.8	6.8	90.1	6.8	22.7	—	0.0	29.5
Income (loss) from continuing operations available to common stockholders	($23.2)	($342.6)	($178.0)	($158.0)	($701.8)	($46.1)	$ 93.5	$ 22.8	($96.8)	($26.6)
Income (loss) from continuing operations — diluted earnings per share	($0.05)	($0.65)	($0.34)	($0.31)	($1.35)	($0.09)	$ 0.18	$ 0.04	($0.19)	($0.05)
Nonrecurring items:										
Power										
Hazelton plant expansion write-off	—	—	3.3	—	3.3	—	—	—	—	—
Strategic realignment-related charges	—	—	5.2	—	5.2	—	—	—	—	—
Impairments and loss accruals for commitments related to assets to have been used in power projects	—	81.8	11.5	50.8	144.1	—	—	—	—	—
Impairment of goodwill(3)	—	57.5	—	3.0	60.5	—	—	—	45.0	45.0
Reversal of Energy Capital Mezzanine Financing accrual	—	(7.0)	—	(6.2)	(13.2)	—	—	—	—	—
Write-off of costs associated with termination of certain projects	—	8.9	(1.0)	—	7.9	—	—	—	—	—
Early retirement expenses	—	4.2	—	—	4.2	—	—	—	—	—
Severance accrual	—	3.0	—	—	3.0	—	0.6	—	—	0.6
Worthington impairment	—	—	—	44.7	44.7	—	—	—	—	—
Capstone stock write-down(3)	—	—	—	2.0	2.0	—	—	—	—	—
Thermogas casualty and environmental costs and claim	—	—	—	4.0	4.0	—	—	—	—	—
Loss on Gulfmark JV dissolution	—	—	—	5.7	5.7	—	—	—	—	—
Accelerated compensation expense associated with workforce reductions	—	—	—	—	—	11.8	—	—	—	11.8
Loss accrual for regulatory issues(3)	—	—	—	—	—	—	20.0	—	—	20.0
Prior period item correction(4)	—	—	—	—	—	—	(105.0)	—	—	(105.0)
Gain on sale of Jackson EMC power contracts	—	—	—	—	—	—	(175.0)	(13.0)	—	(188.0)
Gain on sale of crude contracts and pipeline	—	—	—	—	—	—	(7.1)	—	—	(7.1)
Gain on sale of eSpeed stock	—	—	—	—	—	—	—	(13.5)	—	(13.5)
Hazelton impairment	—	—	—	—	—	—	—	—	44.1	44.1
California rate refund and other accrual adjustments(5)	—	—	—	—	—	—	—	—	33.3	33.3
Total Power nonrecurring items	—	148.4	19.0	104.0	271.4	11.8	(266.5)	(26.5)	122.4	(158.8)
Gas Pipeline										
Cross Bay write-off	—	—	1.6	—	1.6	—	—	—	—	—
Gain on sale of Northern Border Limited Partnership units	—	—	(8.7)	—	(8.7)	—	—	—	—	—
Net impairment on investment Alliance US sale	—	—	11.6	(1.2)	10.4	—	—	—	—	—
Loss on sale of Cove Point	—	—	3.7	—	3.7	—	—	—	—	—
Strategic realignment-related charges	—	—	4.5	—	4.5	—	—	—	—	—
Construction completion fee — received	—	(27.4)	—	—	(27.4)	—	—	—	—	—
Write-offs of terminated gas pipeline projects	—	12.3	—	—	12.3	—	—	—	—	—
Early retirement expenses	—	10.7	—	—	10.7	—	—	—	—	—
Loss accrual for regulatory issue	—	—	—	17.0	17.0	—	—	—	—	—
SCADA property write-off	—	—	—	4.7	4.7	—	—	—	—	—
Write-off of Oneline information system project	—	—	—	—	—	—	25.5	—	—	25.5
Severance accrual	—	—	—	—	—	—	0.9	—	—	0.9
Total Gas Pipeline nonrecurring items	—	(4.4)	12.7	20.5	28.8	—	26.4	—	—	26.4
Exploration & Production										
(Gain) loss on sale of certain E&P properties	(3.9)	—	3.8	1.1	1.0	—	(91.5)	—	—	(91.5)
Gain on sale of Anadarko	—	—	(21.6)	0.2	(21.4)	—	—	—	—	—
Gain on sale of Jonah	—	—	(122.3)	2.0	(120.3)	—	—	—	—	—
Strategic realignment-related charges	—	—	0.1	—	0.1	—	—	—	—	—
Early retirement expenses	—	0.4	—	—	0.4	—	—	—	—	—
Total Exploration & Production nonrecurring	(3.9)	0.4	(140.0)	3.3	(140.2)	—	(91.5)	—	—	(91.5)

items

(Dollars in millions, except for per-share amounts)	2002					2003				
	1st Qtr(1)	2nd Qtr(1)	3rd Qtr(1)	4th Qtr(1)	Year(1)	1st Qtr(1)	2nd Qtr(1)	3rd Qtr	4th Qtr	Year
Midstream Gas & Liquids										
Impairment of WS-1 building	—	—	2.4	—	2.4	—	—	—	—	—
Strategic realignment-related charges	—	—	1.5	—	1.5	—	—	—	—	—
Impairment of Canadian assets(3)	—	—	—	115.0	115.0	—	—	—	—	—
Impairment of Kansas-Hugoton facilities as assets held for sale	—	4.8	1.1	—	5.9	—	—	—	—	—
Impairment of investment in Aux Sable	—	—	—	—	—	—	8.5	5.6	—	14.1
Early retirement expenses	—	0.8	—	—	0.8	—	—	—	—	—
La Maquina depreciable life adjustment	—	—	—	—	—	—	—	4.2	—	4.2
Gain on sale of West Texas LPG Pipeline, L.P.	—	—	—	—	—	—	—	(11.0)	—	(11.0)
Impairment of Canadian assets	—	—	—	—	—	—	—	—	41.7	41.7
Gain on sale of wholesale propane	—	—	—	—	—	—	—	—	(16.2)	(16.2)
Total Midstream Gas & Liquids nonrecurring items	—	5.6	5.0	115.0	125.6	—	8.5	(1.2)	25.5	32.8
Other										
Gain on sale of Mazeikiu Nafta	—	—	(58.5)	—	(58.5)	—	—	—	—	—
Strategic realignment-related charges	—	—	4.9	—	4.9	—	—	—	—	—
Early retirement expenses	—	6.5	—	—	6.5	—	—	—	—	—
Impairment of Wiljet assets/investments	—	—	2.1	—	2.1	—	—	—	—	—
Impairment of Augusta refinery assets	—	—	—	3.0	3.0	—	—	—	—	—
Impairment of Longhorn and Aspen project(6)	—	—	—	—	—	—	49.6	—	—	49.6
Gain on sale of butane blending inventory	—	—	—	—	—	—	—	(9.2)	—	(9.2)
Total Other nonrecurring items	—	6.5	(51.5)	3.0	(42.0)	—	49.6	(9.2)	—	40.4
Nonrecurring items included in segment profit (loss)	(3.9)	156.5	(154.8)	245.8	243.6	11.8	(273.5)	(36.9)	147.9	(150.7)
Nonrecurring items below segment profit (loss)										
Estimated loss on realization of amounts from WilTel Communications Group, Inc. (Investing income (loss) — Corporate)	232.0	15.0	22.9	(1.2)	268.7	—	—	—	—	—
Costs associated with business & liquidity issue resolution (Interest accrued, minority interest, and other income (expense) — net — Various)	—	—	21.7	—	21.7	—	—	—	—	—
Strategic realignment-related charges (General corporate expenses)	—	—	3.6	—	3.6	—	—	—	—	—
Corporate asset impairments (Other income (expense) — net — Corporate)	—	—	4.0	—	4.0	—	—	—	—	—
Convertible preferred stock dividends(3)(Preferred stock dividends — Corporate)	69.4	—	—	—	69.4	—	13.8	—	—	13.8
Gain on disposition of Prudential shares received from demutualization (Other income	—	—	—	—	—	—	—	—	—	—
(expense) — net — Gas Pipeline)	—	(11.0)	—	—	(11.0)	—	—	—	—	—
Early retirement expense (General corporate expenses)	—	6.2	—	—	6.2	—	—	—	—	—
Write-off of James River accrued dividends/investment (Other income (expense) — net -	—	—	—	—	—	—	—	—	—	—
Corporate)	—	—	—	8.5	8.5	—	—	—	—	—
Impairment of cost based investments(3) (Investing income (loss) -Various)	—	—	—	—	—	—	19.1	2.3	—	21.4
Severance accrual (General corporate expenses)	—	—	—	2.7	2.7	—	3.0	—	—	3.0
Executive retirement expenses (General corporate expenses)	—	—	—	2.2	2.2	—	—	—	—	—
Deferred stock award modification (General corporate expenses)	—	—	—	(1.1)	(1.1)	—	—	—	—	—
Impairment of Algar Telecom investment (Investing income (loss) — International)	—	—	—	—	—	12.0	—	1.2	—	13.2
Write-off of capitalized debt expense (Interest accrued	—	—	—	—	—	—	14.5	—	—	14.5

— Corporate)										
Debt tender offer premiums and adjustments (Other income (expense) — net — Corporate)	—	—	—	—	—	—	—	—	66.8	66.8
	301.4	10.2	52.2	11.1	374.9	12.0	50.4	3.5	66.8	132.7
Total nonrecurring items	297.5	166.7	(102.6)	256.9	618.5	23.8	(223.1)	(33.4)	214.7	(18.0)
Tax effect for above items	83.5	39.5	(39.2)	52.4	138.4	9.1	(113.3)	(13.7)	61.3	(56.6)
Recurring income (loss) from continuing operations	$ 190.8	($215.4)	($241.4)	$ 46.5	($221.7)	($31.4)	($16.3)	$ 3.1	$ 56.6	$ 12.0
Recurring diluted earnings per common share	$ 0.37	($0.41)	($0.47)	$ 0.09	($0.43)	($0.06)	$ (0.03)	$ 0.01	$ 0.11	$ 0.02
Weighted-average shares — diluted (thousands)	521,240	520,427	516,901	517,104	516,793	517,652	534,839	524,711	518,502	518,137

(1) **Amounts have been restated to reflect certain operations as discontinued operations.**

(2) **Includes $126.8 million positive valuation adjustment associated with agreement to terminate contract with Allegheny in second quarter 2003.**

(3) **No tax benefit**

(4) **Power recognized $80.7 million of revenue in the second quarter of 2003 from a correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. Results for 2003 include $105 million of revenue related to these prior period items, of which $24 million was recorded prior to the correction.**

(5) **For $5.6 million, no tax benefit**

(6) **For $20.2 million, no tax benefit**

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

	2002					2003				
(Dollars in millions)	**1st Qtr****	**2nd Qtr****	**3rd Qtr****	**4th Qtr****	**Year****	**1st Qtr****	**2nd Qtr****	**3rd Qtr**	**4th Qtr**	**Year**
Segment profit (loss):										
Power *	$283.1	$(497.5)	$(387.6)	$ (22.8)	$(624.8)	$(136.4)	$ 348.0	$ 43.9*	$(121.3)*	$ 134.2
Gas Pipeline	134.7	141.1	147.2	122.1	545.1	151.2	113.9	141.4	148.4	554.9
Exploration & Production	106.5	92.4	228.2	81.5	508.6	113.8	178.7	58.8	50.1	401.4
Midstream Gas & Liquids	53.0	45.6	111.6	(27.0)	183.2	116.2	49.6	74.3	45.9	286.0
Other	(8.8)	(3.7)	47.4	(20.8)	14.1	4.8	(51.7)	4.1	(7.7)	(50.5)
Total segment profit (loss)	**$568.5**	**$(222.1)**	**$ 146.8**	**$133.0**	**$ 626.2**	**$ 249.6**	**$ 638.5**	**$322.5**	$ 115.4	$1,326.0
Nonrecurring adjustments:										
Power	$ —	$ 148.4	$ 19.0	$104.0	$ 271.4	$ 11.8	$(266.5)	$ (26.5)	$ 122.4	$ (158.8)
Gas Pipeline	—	(4.4)	12.7	20.5	28.8	—	26.4	—	—	26.4
Exploration & Production	(3.9)	0.4	(140.0)	3.3	(140.2)	—	(91.5)	—	—	(91.5)
Midstream Gas & Liquids	—	5.6	5.0	115.0	125.6	—	8.5	(1.2)	25.5	32.8
Other	—	6.5	(51.5)	3.0	(42.0)	—	49.6	(9.2)	—	40.4
Total segment nonrecurring adjustments	**$ (3.9)**	**$ 156.5**	**$(154.8)**	**$245.8**	**$ 243.6**	**$ 11.8**	**$(273.5)**	**$ (36.9)**	**$ 147.9**	**$ (150.7)**
Recurring segment profit (loss):										
Power *	$283.1	$(349.1)	$(368.6)	$ 81.2	$(353.4)	$(124.6)	$ 81.5	$ 17.4	$ 1.1	$ (24.6)
Gas Pipeline	134.7	136.7	159.9	142.6	573.9	151.2	140.3	141.4	148.4	581.3
Exploration & Production	102.6	92.8	88.2	84.8	368.4	113.8	87.2	58.8	50.1	309.9
Midstream Gas & Liquids	53.0	51.2	116.6	88.0	308.8	116.2	58.1	73.1	71.4	318.8
Other	(8.8)	2.8	(4.1)	(17.8)	(27.9)	4.8	(2.1)	(5.1)	(7.7)	(10.1)
Total recurring segment profit (loss)	**$564.6**	**$ (65.6)**	**$ (8.0)**	**$378.8**	**$ 869.8**	**$ 261.4**	**$ 365.0**	**$285.6**	**$ 263.3**	**$1,175.3**

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

* Power's segment profit includes the effect of intercompany interest rate swaps entered into with the corporate parent.

** Amounts have been restated to reflect certain operations as discontinued operations.