UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2005

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________to__________

Commission file number 1-4174

THE WILLIAMS COMPANIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	73-0569878
(State of Incorporation)	(IRS Employer Identification Number)
ONE WILLIAMS CENTER TULSA, OKLAHOMA	74172
(Address of principal executive office)	(Zip Code)

Registrant's telephone number: (918) 573-2000

NO CHANGE

Former name, former address and former fiscal year, if changed since last report.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes ☑ No ☐

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at April 30, 2005
Common Stock, $1 par value	570,829,536 Shares

The Williams Companies, Inc.
Index

Part I. Financial Information

Item 1. Financial Statements

Certain matters discussed in this report, excluding historical information, include forward-looking statements — statements that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by words such as “anticipates,” “believes,” “expects,” “planned,” “scheduled,” “could,” “continues,” “estimates,” “forecasts,” “might,” “potential,” “projects” or similar expressions. Although we believe these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document. Additional information about issues that could cause actual results to differ materially from forward-looking statements is contained in our 2004 Form 10-K.

The Williams Companies, Inc.
Consolidated Statement of Operations
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended March 31, 2005	2004*
Revenues:		
Power	$ 2,064.9	$ 2,296.4
Gas Pipeline	335.3	359.0
Exploration & Production	249.0	165.2
Midstream Gas & Liquids	807.0	631.8
Other	7.0	12.6
Intercompany eliminations	(509.2)	(395.0)
Total revenues	2,954.0	3,070.0
Segment costs and expenses:		
Costs and operating expenses	2,390.3	2,690.9
Selling, general and administrative expenses	73.5	85.5
Other (income) expense — net	(1.8)	8.3
Total segment costs and expenses	2,462.0	2,784.7
General corporate expenses	28.0	32.0
Operating income (loss):		
Power	113.0	(11.1)
Gas Pipeline	156.0	143.9
Exploration & Production	100.2	48.6
Midstream Gas & Liquids	121.5	106.1
Other	1.3	(2.2)
General corporate expenses	(28.0)	(32.0)
Total operating income	464.0	253.3
Interest accrued	(164.7)	(243.3)
Interest capitalized	1.1	4.0
Interest rate swap loss	—	(8.1)
Investing income	31.0	10.4
Minority interest in income of consolidated subsidiaries	(5.2)	(4.8)
Other income — net	5.5	0.8
Income from continuing operations before income taxes	331.7	12.3
Provision for income taxes	129.5	12.3
Income from continuing operations	202.2	—
Income (loss) from discontinued operations	(1.1)	9.9
Net income	$ 201.1	$ 9.9
Basic earnings per common share:		
Income from continuing operations	$ .36	$ —
Income from discontinued operations	—	.02
Net income	$ .36	$ .02
Weighted-average shares (thousands)	564,437	519,485
Diluted earnings per common share:		
Income from continuing operations	$ .34	$ —
Income from discontinued operations	—	.02
Net income	$ .34	$ .02
Weighted-average shares (thousands)	599,422	519,485
Cash dividends per common share	$ .05	$ .01

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	March 31, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,210.0	$ 930.0
Restricted cash	47.1	77.4
Accounts and notes receivable less allowance of $97.8 ($98.8 in 2004)	1,243.4	1,422.8
Inventories	222.8	261.1
Derivative assets	4,237.4	2,961.0
Margin deposits	168.7	131.7
Assets of discontinued operations	13.3	13.6
Deferred income taxes	120.7	89.0
Other current assets and deferred charges	167.6	157.0
Total current assets	7,431.0	6,043.6
Restricted cash	35.8	35.3
Investments	1,322.2	1,316.2
Property, plant and equipment, at cost	16,538.7	16,452.8
Less accumulated depreciation and depletion	(4,686.4)	(4,566.0)
Property, plant and equipment — net	11,852.3	11,886.8
Derivative assets	4,054.5	3,025.3
Goodwill	1,014.5	1,014.5
Other assets and deferred charges	723.8	671.3
Total assets	$ 26,434.1	$ 23,993.0
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 954.9	$ 1,043.2
Accrued liabilities	924.9	991.7
Liabilities of discontinued operations	1.6	1.6
Derivative liabilities	4,274.3	2,859.3
Long-term debt due within one year	99.5	250.1
Total current liabilities	6,255.2	5,145.9
Long-term debt	7,650.4	7,711.9
Deferred income taxes	2,515.3	2,470.1
Derivative liabilities	3,795.9	2,735.7
Other liabilities and deferred income	863.9	873.8
Contingent liabilities and commitments (Note 11)		
Minority interests in consolidated subsidiaries	92.3	99.7
Stockholders' equity:		
Common stock, $1 per share par value, 960 million shares authorized, 573.7 million issued in 2005, 561.2 million issued in 2004	573.7	561.2
Capital in excess of par value	6,282.6	6,005.9
Accumulated deficit	(1,134.0)	(1,306.5)
Accumulated other comprehensive loss	(407.4)	(244.2)
Other	(15.2)	(21.9)
	5,299.7	4,994.5
Less treasury stock (at cost), 3.2 million shares of common stock in 2005 and 2004	(38.6)	(38.6)
Total stockholders' equity	5,261.1	4,955.9
Total liabilities and stockholders' equity	$ 26,434.1	$ 23,993.0

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

	Three months ended March 31, 2005	Three months ended March 31, 2004*
	(Millions)	
OPERATING ACTIVITIES:		
Income from continuing operations	$ 202.2	$ —
Adjustments to reconcile to cash provided (used) by operations:		
Depreciation, depletion and amortization	178.2	160.4
Provision for deferred income taxes	118.9	4.7
Provision for loss on investments, property and other assets	(.5)	7.4
Net (gain) loss on disposition of assets	(12.8)	1.3
Minority Interest in income of consolidated subsidiaries	5.2	4.8
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	159.7	161.2
Inventories	38.3	38.9
Margin deposits	(37.0)	(85.4)
Other current assets and deferred charges	4.5	67.3
Accounts payable	(103.8)	(210.9)
Accrued liabilities	(119.1)	(114.6)
Changes in current and noncurrent derivative assets and liabilities	(91.7)	114.5
Other, including changes in noncurrent assets and liabilities	(37.7)	6.1
Net cash provided by operating activities of continuing operations	304.4	155.7
Net cash used by operating activities of discontinued operations	—	(52.9)
Net cash provided by operating activities	304.4	102.8
FINANCING ACTIVITIES:		
Payments of notes payable	—	(3.3)
Payments of long-term debt	(215.5)	(707.7)
Proceeds from issuance of common stock	288.0	4.8
Fees paid to amend credit facilities	(17.9)	—
Dividends paid	(28.5)	(5.2)
Payments/dividends to minority interests	(12.6)	(1.2)
Changes in restricted cash	29.8	6.3
Changes in cash overdrafts	15.7	(27.4)
Other — net	(.2)	(.5)
Net cash provided (used) by financing activities of continuing operations	58.8	(734.2)
Net cash used by financing activities of discontinued operations	—	(.6)
Net cash provided (used) by financing activities	58.8	(734.8)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(222.9)	(127.8)
Proceeds from dispositions	6.7	.9
Contract termination payment	87.9	—
Purchases of investments/advances to affiliates	(26.3)	(.4)
Purchases of restricted investments	—	(235.9)
Proceeds from sales of businesses	.3	279.9
Proceeds from sale of restricted investments	—	331.2
Proceeds received on sale of note from WilTel	54.7	—
Proceeds from dispositions of investments and other assets	8.6	74.8
Other — net	7.8	(9.3)
Net cash provided (used) by investing activities of continuing operations	(83.2)	313.4
Net cash used by investing activities of discontinued operations	—	(.9)
Net cash provided (used) by investing activities	(83.2)	312.5
Increase (decrease) in cash and cash equivalents	280.0	(319.5)
Cash and cash equivalents at beginning of period	930.0	2,318.2
Cash and cash equivalents at end of period	$ 1,210.0	$ 1,998.7

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

The Williams Companies, Inc.
Notes To Consolidated Financial Statements
(Unaudited)

1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at March 31, 2005, and results of operations and cash flows for the three months ended March 31, 2005 and 2004.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

2. Basis of presentation

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the accompanying consolidated financial statements and notes reflect the results of operations, financial position and cash flows of the following components as discontinued operations (see Note 4):

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and
- our straddle plants in western Canada, previously part of the Midstream Gas & Liquids (Midstream) segment.

During fourth-quarter 2004, we reclassified the operations of Gulf Liquids New River Project LLC (Gulf Liquids) to continuing operations within our Midstream segment in accordance with Emerging Issues Task Force (EITF) Issue No. 03-13, "Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations'' (EITF 03-13), which was issued in the fourth quarter. Under the provisions of EITF 03-13, Gulf Liquids activities no longer qualified for reporting as discontinued operations, based on management's expectation that we will continue to have significant commercial activity with the disposed entity. The operations of Gulf Liquids were reclassified to continuing operations within our Midstream segment. All periods presented reflect this reclassification.

At March 31, 2005, the operations of Gulf Liquids are classified as held for sale and are included in Other current assets and Accrued liabilities on the Consolidated Balance Sheet. The Gulf Liquids assets and liabilities are not material to the Consolidated Balance Sheet. We are currently negotiating purchase and sale agreements related to the sale of these assets, and we expect the sale of the operations to close by the end of the second quarter of 2005.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations.

We have restated all segment information in the Notes to Consolidated Financial Statements for the prior periods presented to reflect the discontinued operations noted above, consistent with the presentation in our 2004 Form 10-K.

Notes (Continued)

3. Provision for income taxes

The provision for income taxes from continuing operations includes:

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Current:		
Federal	$ 4.3	$ 3.3
State	5.2	1.8
Foreign	1.1	2.5
	10.6	7.6
Deferred:		
Federal	102.9	.1
State	16.0	2.3
Foreign	—	2.3
	118.9	4.7
Total provision	$ 129.5	$ 12.3

The effective income tax rate for the three months ended March 31, 2005, is greater than the federal statutory rate due primarily to the effect of state income taxes and an accrual for income tax contingencies, partially offset by net foreign operations.

The effective income tax rate for the three months ended March 31, 2004, is significantly greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations and an accrual for income tax contingencies.

4. Discontinued operations

The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of March 31, 2005, and also meet all requirements to be treated as discontinued operations. Therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

For the three months ended March 31, 2005, discontinued operations did not generate any revenues and reported a loss of $1.1 million. For the three months ended March 31, 2004, discontinued operations included revenues of $289.8 million and income of $9.9 million. Each period includes various adjustments related to previously reported discontinued operations.

At March 31, 2005, and December 31, 2004, we had total assets of discontinued operations of $13.3 million and $13.6 million respectively. We had total liabilities of discontinued operations of $1.6 million at March 31, 2005, and December 31, 2004. The balances include certain Alaska retail operations that were not included in the March 31, 2004, sale but that remain held for sale. The assets and liabilities from discontinued operations are reflected on the Consolidated Balance Sheet as current beginning in the period they are both approved for sale and expected to be sold within twelve months.

2004 completed transactions

Canadian straddle plants

During the third quarter of 2004, we completed the sale of the Canadian straddle plants for approximately $544 million in U.S. funds. The operations were part of the Midstream segment.

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline and related assets for approximately $304 million (consisting of $279 million in cash and a $25 million short-term receivable, which was subsequently collected in the second quarter of 2004), subject to closing adjustments for items such as the value of petroleum inventories. We regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiation process using a probability-weighted approach. We recognized a $3.6 million pre-tax gain on the sale. These operations were part of the previously reported Petroleum Services segment.

Notes (Continued)

5. Earnings per share from continuing operations

Basic and diluted earnings per common share are computed as follows:

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Dollars in millions, except per share amounts; shares in thousands)	
Income from continuing operations available to common stockholders for basic and diluted earnings per share	$ 202.2	$ —
Basic weighted-average shares (1)	564,437	519,485
Effect of dilutive securities:		
Unvested deferred shares	2,565	—
Stock options	4,872	—
Convertible debentures	27,548	—
Diluted weighted-average shares	599,422	519,485
Earnings per share from continuing operations:		
Basic	$ .36	$ —
Diluted	$ .34	$ —

(1) In February 2005 and October 2004, we issued 10.9 million and 33.1 million shares, respectively, of common stock associated with our FELINE PACS units (see Note 10).

For the three months ended March 31, 2004, approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of Diluted earnings per common share. Inclusion of these shares would have been antidilutive. If no other components used to calculate Diluted earnings per common share change, we estimate the assumed conversion of convertible debentures would become dilutive and therefore be included in Diluted earnings per common share at an Income from continuing operations applicable to common stock amount of $48.6 million for the three months ended March 31, 2004.

For the three months ended March 31, 2004, approximately 3.8 million weighted-average stock options and approximately 2.4 million weighted-average unvested deferred shares have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The unvested deferred shares outstanding at March 31, 2005 will vest over the period from May 2005 to March 2008.

The table below includes information related to options that were outstanding at March 31 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first-quarter weighted-average market price of our common shares.

	2005	2004
Options excluded (millions)	9.0	14.8
Weighted-average exercise prices of options excluded	$ 28.45	$ 22.40
Exercise price ranges of options excluded	$ 18.15 - $42.29	$ 10.00 - $42.52
First-quarter weighted-average market price	$ 17.51	$ 9.97

6. Employee benefit plans

Net periodic pension and other postretirement benefit expense for the three months ended March 31, 2005 and 2004 are as follows:

	Pension Benefits Three months ended March 31, 2005	Pension Benefits Three months ended March 31, 2004	Other Postretirement Benefits Three months ended March 31, 2005	Other Postretirement Benefits Three months ended March 31, 2004
	(Millions)			
Service cost	$ 6.1	$ 7.0	$ .9	$ 1.5
Interest cost	12.0	14.5	3.7	5.7
Expected return on plan assets	(15.2)	(14.9)	(3.3)	(3.1)
Amortization of transition obligation	—	—	—	.6
Amortization of prior service cost (credit)	(.4)	(.7)	(1.2)	.2
Recognized net actuarial loss	3.2	3.7	—	—
Regulatory asset amortization	.5	1.1	1.6	1.6
Settlement/curtailment expense	1.9	—	—	—
Net periodic pension and postretirement benefit expense	$ 8.1	$ 10.7	$ 1.7	$ 6.5

As of March 31, 2005, we have contributed $29.2 million to our pension plans and $3.8 million to our other postretirement benefit plans. We presently anticipate contributing approximately an additional $17 million to our pension plans in 2005 for a total of approximately $46 million. We presently anticipate contributing approximately an additional $11 million to our other postretirement benefit plans in 2005 for a total of approximately $15 million.

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plans for retirees include prescription drug coverage. We amended our health care plans for retirees in the fourth quarter of 2004 to coordinate and pay secondary to any part of Medicare, including prescription drug benefits covered by Medicare Part D. As a result of the amendment, our plans are not actuarially equivalent to Medicare Part D. The amendment decreased our benefit obligation by $75.5 million in 2004. The net reduction to the obligation is being amortized over the average remaining years of service to full eligibility for benefits beginning in 2005 and is reflected in the amortization of prior service credit for other postretirement benefits in the previous table.

7. Stock-based compensation

Employee stock-based awards are accounted for under Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees,” and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock option equals the market price of the underlying stock on the date of grant. The following table illustrates the effect on net income and earnings per share for the three months ended March 31, 2005 and 2004 if we had applied the fair value, estimated using the Black-Scholes pricing model, recognition provisions of SFAS No. 123, “Accounting for Stock-Based Compensation.”

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Net income, as reported	$ 201.1	$ 9.9
Add: Stock-based employee compensation expense included in the Consolidated Statement of Operations, net of related tax effects	1.8	4.4
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(5.5)	(7.4)
Pro forma net income	$ 197.4	$ 6.9
Earnings per share:		
Basic-as reported	$ .36	$ .02
Basic-pro forma	$ .35	$ .01
Diluted-as reported	$ .34	$ .02
Diluted-pro forma	$ .33	$ .01

Notes (Continued)

Since compensation expense for stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

8. Inventories

Inventories at March 31, 2005 and December 31, 2004 are as follows:

	March 31, 2005	December 31, 2004
	(Millions)	
Finished goods:		
Refined products	$ 2.1	$ .8
Natural gas liquids	53.3	63.2
	55.4	64.0
Natural gas in underground storage	101.5	133.1
Materials, supplies and other	65.9	64.0
	$ 222.8	$ 261.1

9. Debt and banking arrangements

Revolving credit and letter of credit facilities

In January 2005, we terminated our previous two unsecured bank revolving credit facilities totaling $500 million and replaced them with two new facilities. The new credit facilities contain the same terms as the previous credit agreements, but almost all of the restrictive covenants and events of default were removed or made less restrictive. We paid $17.9 million in fees as a result of the termination and replacement, which will be amortized over the life of the facilities. At March 31, 2005, letters of credit totaling $492 million have been issued under these facilities and no revolving credit loans were outstanding.

Under our $1.275 billion secured revolving credit facility, letters of credit totaling $455 million have been issued and no revolving credit loans were outstanding at March 31, 2005.

Retirements

During January 2005, we retired $200 million of 6.125% notes issued January 15, 1998, by Transcontinental Gas Pipe Line Corporation (Transco), which matured January 15, 2005.

10. Stockholders' equity

In January 2002, we issued $1.1 billion of 6.5 percent notes payable in 2007 that were subject to remarketing in 2004. Each note was bundled with an equity forward contract (together, the FELINE PACS units) and sold in a public offering for $25 per unit. The equity forward contract required the holder of each note to purchase one share of our common stock for $25 three years from issuance of the contract. In the fourth quarter of 2004, we exchanged approximately 33.1 million of the 44 million issued and outstanding FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. On the February 16, 2005, settlement date of the equity forward contracts, the holders of the remaining 10.9 million equity forward contracts purchased one share of our common stock for $25, resulting in cash proceeds of approximately $273 million and an increase in Capital in excess of par of approximately $262 million.

11. Contingent liabilities and commitments

Rate and regulatory matters and related litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $5 million for potential refund as of March 31, 2005.

Notes (Continued)

Issues resulting from California energy crisis

Subsidiaries of our Power segment are engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 have been challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges include refund proceedings, California Independent System Operator (ISO) fines, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that have substantially resolved each of these issues. However, certain issues remain open at the FERC and for other non-settling parties, such as the United States Department of Justice (DOJ).

Refund proceedings

Although we have entered into the State Settlement and Utilities Settlement which resolve the refund issues among the settling parties, we have potential refund exposure to non-settling parties (e.g., various California end users that have not agreed to opt into the Utilities Settlement). As a part of the Utilities Settlement, we funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the non-settling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable of approximately $29 million at March 31, 2005. Collection of the interest is subject to the conclusion of this proceeding. A request for rehearing of the order approving the Utilities Settlement is pending at the FERC. Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceeding, including the refund period, are now pending at the Ninth Circuit Court of Appeals.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint with the FERC against us seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-Day Contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleged that the rates contained in the contracts are unjust and unreasonable. On June 26, 2003, the FERC affirmed the administrative law judge's initial decision dismissing the complaints. PacifiCorp has appealed the FERC's order to the United States Court of Appeals for the Ninth Circuit after the FERC denied rehearing of its order on November 10, 2003.

Investigations of alleged market manipulation

As a result of various allegations and FERC orders, in 2002 the FERC initiated investigations of manipulation of the California gas and power markets. As they related to us, these investigations included economic and physical withholding, so-called "Enron Gaming Practices" and gas index manipulation. Each of these FERC investigations of alleged market manipulation was resolved pursuant to the Utilities Settlement that is discussed above in *Refund proceedings.*

As also discussed below in ***Reporting of natural gas-related information to trade publications,*** on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets. We have completed our response to the subpoena. This subpoena is a part of the broad DOJ investigation regarding gas and power trading.

Long-term contracts

In February 2001, during the height of the California energy crisis, we entered into a long-term power contract with the State of California to assist in stabilizing its market. The State of California later sought to rescind this contract. Following settlement discussions between the State and us on the contract issue as well as other state initiated proceedings and allegations of market manipulation, we entered into the State Settlement that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The State Settlement does not extend to criminal matters or matters of willful fraud, but did resolve civil complaints brought by the California Attorney General against us and the State of California's refund claims that are discussed above. In addition, the State Settlement resolved ongoing investigations by the States of California, Oregon and Washington. Certain private class action and other civil plaintiffs who have initiated class action litigation against us and others in California based on allegations against us with respect to the California energy crisis also executed the State Settlement. On June 29, 2004, the court approved the State Settlement, making it effective as to plaintiffs and terminating the class actions as to us. A limited group did opt out of the State Settlement. An appeal of the approval order is currently pending. Litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of March 31, 2005, pursuant to the terms of the State Settlement, we have transferred ownership of six LM6000 gas powered electric turbines, have made three payments totaling $87 million to the California Attorney General, and have funded a $15 million fee and expense fund associated with civil actions that are subject to the State Settlement. An additional $60 million, previously accrued, remains to be paid to the California Attorney General (or his designee) over the next five years, with the final payment of $15 million due on January 1, 2010.

Redondo Beach Taxes

On February 5, 2005, Power received a tax assessment letter, addressed to AES Redondo Beach, L.L.C. and Power, from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. On the same date, Power was served with a subpoena from the city related to the tax assessment. Under Power’s tolling agreement related to the Redondo Beach generating facility, we believe that AES Redondo Beach is responsible for taxes of the nature asserted by the city.

Reporting of natural gas-related information to trade publications

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. As noted above, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We have completed our response to the subpoena. On December 17, 2004, a former trader with Power pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. The DOJ’s investigation of us in this matter is continuing, and it is reasonably possible that material penalties could result. However, a reasonable estimate of such amount cannot be determined at this time. In addition, the Commodity Futures Trading Commission (CFTC) has conducted an investigation of us regarding this issue. On July 29, 2003, we reached a settlement with the CFTC in which in exchange for $20 million, the CFTC closed its investigation, and we did not admit or deny allegations that we had engaged in false reporting or attempted manipulation. Civil suits based on allegations of manipulating the gas indices have been brought against us and others in federal court in New York, Tennessee, Washington, Oregon and California and in state court in California.

Investigations related to natural gas storage inventory

We responded to a subpoena from the CFTC and inquiries from the FERC related to investigations involving natural gas storage inventory issues. Through some of our subsidiaries, we own and operate natural gas storage facilities. On August 30, 2004, the CFTC announced that it had concluded its investigation. The FERC inquiries relate to the sharing of non-public data concerning inventory levels and the potential uses of such data in natural gas trading. The FERC investigation is continuing and we are engaged in discussions with FERC staff that are likely to result in an ultimate disposition of this matter through a settlement that would include some amount of penalty and refund. We have recorded an accrual for our estimate of the future payment.

Mobile Bay expansion

On December 3, 2002, an administrative law judge at the FERC issued an initial decision in Transco’s general rate case which, among other things, rejected the recovery of the costs of Transco’s Mobile Bay expansion project from its shippers on a “rolled-in” basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. The administrative law judge’s initial decision is subject to review by the FERC. On March 26, 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge’s holding and accepted Transco’s proposal for rolled-in rates. Power holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Power could have been subject to surcharges of approximately $64 million, excluding interest, through March 31, 2005, in addition to increased costs going forward. On April 26, 2004, several parties, including Transco filed requests for rehearing of the FERC’s March 26, 2004 order. These requests are still pending.

Enron bankruptcy

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively “Enron”) related to Enron’s bankruptcy filed in December 2001. In March 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. On December 23, 2003, Enron filed objections to these claims. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price, plus interest assessed at an annual rate of 7.5 percent, for that portion of the claims still subject to objections beginning 90 days following the initial objection. To date, the purchaser has not demanded repayment.

Notes (Continued)

Environmental matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other programs concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At March 31, 2005, Transco had accrued liabilities of $23 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances.

We also accrue environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At March 31, 2005, we had accrued liabilities totaling approximately $8 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

In August 2004, the New Mexico Environment Department (NMED) issued a Notice of Violation (NOV) to one of our subsidiaries, Williams Field Services Company (WFS), alleging various air permit violations primarily related to WFS's alleged failure to control volatile organic compound emissions from three conventional dehydrators in 2001. The NOV specified that the maximum statutory penalty for such violations is approximately $13.7 million. NMED and WFS are negotiating a possible resolution to this matter and WFS anticipates that any proposed penalty will be significantly lower than the maximum statutory amount. Additionally, in August 2004, WFS discovered and self-disclosed to the NMED that WFS was out of compliance with certain requirements of the operating permit issued under Title V of the Clean Air Act Amendments of 1990 at the Kutz gas processing plant. NMED and WFS are also negotiating a possible resolution to this matter.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At March 31, 2005, we had accrued liabilities of approximately $11 million for such excess costs.

We are also in discussions with defendants involved in two class action damages lawsuits involving this former chemical fertilizer business. Settlement among those defendants was judicially approved in October 2004. We were not a named defendant in the settled lawsuits, but have contractual obligations to participate with the named defendants in the ongoing environmental remediation. One defendant has filed a Motion to Compel us to participate in arbitration regarding the contractual obligations. A hearing was held on that Motion on September 2, 2004 and the judge ordered the Motion to Compel and subsequent issues severed from the class action. On November 3, 2004, we removed the severed case to the United States District Court in the Northern District of Florida in Pensacola. Agrico filed its motion to remand on November 22, 2004. We filed a subsequent Motion to Dismiss on January 21, 2005. A hearing on the Motion to Remand was held on March 23, 2005. The Court did not rule from the bench and its decision is still pending.

Other

At March 31, 2005, we had accrued environmental liabilities totaling approximately $28 million related primarily to our:

- potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;
- discontinued petroleum refining facilities; and
- former exploration and production and mining operations.

These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining's Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. On August 25, 2004, Williams Refining and its new owner met with the EPA and the DOJ to discuss alleged violations and proposed penalties due to noncompliance issues identified in the multi-media report, including the benzene NESHAP issue. Discussion between the EPA, the DOJ and Williams Refining to resolve the allegations of noncompliance are ongoing. In connection with the sale of the Memphis refinery in March 2003, there are certain indemnification obligations to the purchaser.

In July 2004, the Oklahoma Department of Environmental Quality (ODEQ) issued a NOV alleging various air permit violations associated with the operation of the Dry Trail gas processing plant, which we sold in November 2003. The NOV was issued to WFS and the purchaser of the plant. On April 14, 2005, the ODEQ issued a letter to the current Dry Trail plant owners assessing a penalty under the NOV of approximately $700,000. The current owner has asserted an indemnification claim to us for payment of the penalty. We are analyzing the proposed penalty and anticipate negotiation of a resolution with the current plant owner and the ODEQ.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

Other legal matters

Royalty indemnifications

In connection with agreements to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined.

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently a defendant in one lawsuit in which a producer has asserted damages, including interest calculated through March 31, 2005, of approximately $10 million. On July 11, 2003, at the conclusion of the trial, the judge ruled in Transco's favor and subsequently entered a formal judgment. However, the plaintiff has appealed.

Will Price (formerly Quinque)

On June 8, 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs allege that the defendants, including us, have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. After the court denied class action certification and while motions to dismiss for lack of personal jurisdiction were pending, the court granted the plaintiffs' motion to amend their petition on July 29, 2003. The fourth amended petition, which was filed on July 29, 2003, deletes all of our defendants except two Midstream subsidiaries. All defendants have opposed class certification, and a hearing on plaintiffs' second motion to certify the class was held on April 1, 2005. We anticipate receiving a decision later in 2005.

Grynberg

In 1998, the DOJ informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. In connection with our sale of Kern River and Texas Gas, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg has also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg *qui tam* cases, including the action filed in federal court in Colorado against us. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg *qui tam* cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remain pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims. The defendants have filed a number of joint motions to dismiss Grynberg's claims on subject matter jurisdictional bases. Oral argument on these motions occurred on March 17 and 18, 2005, and we expect a preliminary decision in the second quarter of 2005.

On August 6, 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in the state court in Denver, Colorado. The complaint alleges that the defendants have used mismeasurement techniques that distort the BTU heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that defendants inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1.4 million. Our motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph was granted in January 2003. In September 2004, Grynberg successfully moved to lift the stay and filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in January 2005, denying liability for the damages claimed. Trial in this case has been set for May 2006.

Securities class actions

Numerous shareholder class action suits have been filed against us in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that we and co-defendants, WilTel Communications (WilTel), previously an owned subsidiary known as Williams Communications, and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. These cases were filed against us, certain corporate officers, all members of our board of directors and all of the offerings' underwriters. WilTel is no longer a defendant as a result of its bankruptcy. These cases have all been consolidated and an order has been issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification from these cases. If granted, costs incurred as a result of these indemnifications will not be covered by our insurance policies. The amended complaint of the WilTel securities holders was filed in September 2002, and the amended complaint of our securities holders was filed in October 2002. This amendment added numerous claims related to Power. Defendants moved to dismiss the complaints and the Court largely denied the motions. The parties are currently engaged in discovery. On April 2, 2004, the lead plaintiff for the purported class of our securities holders filed a partial motion for summary judgment with respect to certain disclosures made in connection with our public offerings during the class period. That lead plaintiff subsequently filed to withdraw from the proceeding and a new process was held to determine the lead plaintiff. This process has concluded with the appointment of a new lead plaintiff and lead counsel and the motion for summary judgment is no longer being pursued. The appointment of a new lead plaintiff also resulted in a revised schedule with a trial date currently set for August 16, 2006. Derivative shareholder suits have been filed in state court in Oklahoma, all based on similar allegations. The state court approved motions to consolidate and to stay these Oklahoma suits pending action by the federal court in the shareholder suits. We have directors and officers insurance which we believe provides coverage for these claims, but there can be no assurance that the ultimate resolution of this litigation will not include some amount outside of insurance coverage.

Notes (Continued)

In addition, four class action complaints have been filed against us, the members of our Board of Directors and members of our benefits and investment committees under the Employee Retirement Income Security Act (ERISA) by participants in our 401(k) plan. A motion to consolidate these suits has been approved. In July 2003, the court dismissed us and our Board from the ERISA suits, but not the members of the benefits and investment committees to whom we might have an indemnity obligation. If it is determined that we have an indemnity obligation, we expect that any costs incurred will be covered by our insurance policies. On June 7, 2004, the Court granted plaintiffs' request to amend their complaint to add additional investment committee members and to again name the Board of Directors. On December 21, 2004, the Court denied the Plaintiffs' Motion for Partial Summary Judgment against the Director Defendants and denied the Motions to Dismiss filed by the Directors and certain Committee Defendants. On April 26, 2005, Plaintiffs filed a Third Amended Complaint again seeking to add us as a defendant in this matter. The U.S. Department of Labor is also independently investigating our employee benefit plans. We are currently engaged in preliminary mediated settlement discussions related to this matter.

Oklahoma securities investigation

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of us and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. We have no pending inquiries in this investigation, but are committed to cooperate fully in the investigation.

Federal Income Tax Litigation

One of our wholly-owned subsidiaries, Transco Coal Gas Company, is engaged in a dispute with the Internal Revenue Service (IRS) regarding the recapture of certain income tax credits associated with the construction of a coal gasification plant in North Dakota by Great Plains Gasification Associates, in which Transco Coal Gas Company was a partner. The IRS has taken alternative positions that allege a disposition date for purposes of tax credit recapture that is earlier than the position taken in the partnership tax return. On August 23, 2001, we filed a petition in the U.S. Tax Court to contest the adjustments to the partnership tax return proposed by the IRS. Certain settlement discussions have taken place since that date. During the fourth quarter of 2004, we determined that a reasonable settlement with the IRS could not be achieved. We filed a Motion for Summary Judgment with the Tax Court, which was heard, and denied, in January 2005. The matter was then tried before the Tax Court in February 2005. We continue to believe that the return position of the partnership is with merit. However, it is reasonably possible that the Tax Court could render an unfavorable decision that could ultimately result in estimated income taxes and interest of up to approximately $115 million in excess of the amount currently accrued.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI) is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. Due to the sale of WAPI's interests on March 31, 2004, no future Quality Bank liability will accrue but we are responsible for any liability that existed as of that date including potential liability for any retroactive payments that might be awarded in these proceedings for the period prior to March 31, 2004. The FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions during the third quarter of 2004. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Interest on the Quality Bank accrual is being accrued each quarter. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at March 31, 2005. We filed a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and our reply briefs on February 1, 2005. Decisions from the Commissions may be issued before the end of 2005 or early in 2006. Settlement discussions have been initiated. Absent the completion of any settlements, it is unlikely that we will be required to make any payments with respect to this matter until sometime after the Commission decisions.

Deepwater construction litigation

In a lawsuit pending in federal court in Houston, Texas, Technip Offshore, Inc. (Technip) is seeking approximately $8.6 million from two of our subsidiaries. The suit alleges that we breached a contract for the construction of deepwater export pipelines connected to the Devils Tower Spar in the Gulf of Mexico. We have filed counterclaims seeking $4.2 million in liquidated delay damages. Each party has posted a letter of credit covering the value of the claims pending against it.

Notes (Continued)

Colorado royalty litigation

On June 27, 2002, a royalty owner in the Piceance basin of Colorado filed suit against one of our Exploration & Production subsidiaries alleging that we breached our lease agreements and violated the Colorado Deceptive Trade Practices Act (CDTA) by making various deductions from his royalty payments from 1996 to date. On August 2, 2004, the jury returned its verdict in the amount of $4.1 million for the plaintiff. The verdict included a finding under the CDTA which could have potentially tripled the damage award. On November 30, 2004, the court issued an order setting aside the plaintiff's CDTA claims, but left intact the $4.1 million award. We are appealing the judgment to the Colorado Court of Appeals.

San Juan basin gas entitlements

One of our Exploration & Production subsidiaries is involved in a dispute with another joint interest owner in multiple federal oil and gas units located in the San Juan basin. The dispute involves various accounting issues relating to payout determinations in these federal units and associated claims for retroactive adjustment of entitlements to gas production. We have tentatively settled these disputes for approximately $23.5 million subject to execution of definitive agreements.

Other divestiture indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided. At March 31, 2005, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

Commitments

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At March 31, 2005, Power's estimated committed payments under these contracts range from approximately $401 million to $424 million annually through 2017 and decline over the remaining five years to $59 million in 2022. Total committed payments under these contracts over the next eighteen years are approximately $6.2 billion.

Guarantees

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to substantially exceed the minimum purchase price.

Notes (Continued)

A foreign bank is a defendant in litigation related to a loan they provided to us. We have repaid the loan and indemnified the bank for legal fees and potential losses that may result from this litigation. We are unable to determine the maximum amount of future payments that we could be required to pay as it is dependent upon the ultimate resolution of the claim. However, we believe the probability is remote that a judgment will be made against the bank that we will have to pay. We have accrued $0.1 million at March 31, 2005, related to this guarantee.

We are required by certain foreign lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any domestic taxes required to be paid by the foreign lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings, generally continue indefinitely unless limited by the underlying tax regulations, and have no carrying value. We have never been called upon to perform under these indemnifications.

We have guaranteed commercial letters of credit totaling $17 million on behalf of ACCROVEN. These expire in January 2006, have no carrying value and are fully collateralized with cash.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042 and have a maximum exposure of approximately $49 million at March 31, 2005. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $44 million at March 31, 2005, and is recorded as a non-current liability.

We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at March 31, 2005.

12. Comprehensive income (loss)

Comprehensive income (loss) from both continuing and discontinued operations is as follows:

	Three months ended March 31,	
	2005	2004
	(Millions)	
Net income	$ 201.1	$ 9.9
Other comprehensive income (loss):		
Net realized losses on securities	—	3.0
Unrealized losses on derivative instruments	(328.6)	(184.6)
Net reclassification into earnings of derivative instrument losses	67.8	46.7
Foreign currency translation adjustments	(2.2)	(5.3)
Minimum pension liability adjustment	—	.7
Other comprehensive loss before taxes	(263.0)	(139.5)
Income tax benefit on other comprehensive loss	99.8	51.4
Other comprehensive loss	(163.2)	(88.1)
Comprehensive income (loss)	$ 37.9	$ (78.2)

13. Segment disclosures

Segments and reclassification of operations

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Other primarily consists of corporate operations and certain continuing operations that were included within the previously reported International and Petroleum Services segments.

Segments — performance measurement

We currently evaluate performance based upon 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. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Notes (Continued)

During 2004, Power 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 interest rate swaps with external counterparties are shown as Interest rate swap loss in the Consolidated Statement of Operations below operating income. These swaps were terminated in the fourth quarter.

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. External revenues of our Exploration & Production segment include third-party oil and gas sales, more than offset by transportation expenses and royalties due third parties on intercompany sales.

The following tables reflect the reconciliation of revenues and operating income (loss) as reported in the Consolidated Statement of Operations to segment revenues and segment profit (loss).

	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
			(Millions)				
Three months ended March 31, 2005							
Segment revenues:							
External	$ 1,851.0	$ 331.8	$ (27.9)	$ 796.3	$ 2.8	$ —	$ 2,954.0
Internal	213.9	3.5	276.9	10.7	4.2	(509.2)	—
Total segment revenues	$ 2,064.9	$ 335.3	$ 249.0	$ 807.0	$ 7.0	$ (509.2)	$ 2,954.0
Segment profit (loss)	$ 114.1	$ 167.4	$ 103.7	$ 128.6	$ (4.1)	$ —	$ 509.7
Less:							
Equity earnings	1.1	11.4	3.5	7.1	(5.4)	—	17.7
Segment operating income	$ 113.0	$ 156.0	$ 100.2	$ 121.5	$ 1.3	$ —	492.0
General corporate expenses							(28.0)
Consolidated operating income							$ 464.0
Three months ended March 31, 2004							
Segment revenues:							
External	$ 2,103.9	$ 355.3	$ (14.8)	$ 622.8	$ 2.8	$ —	$ 3,070.0
Internal	170.9	3.7	180.0	9.0	9.8	(373.4)	—
Total segment revenues	2,274.8	359.0	165.2	631.8	12.6	(373.4)	3,070.0
Less intercompany interest rate swap loss	(21.6)	—	—	—	—	21.6	—
Total revenues	$ 2,296.4	$ 359.0	$ 165.2	$ 631.8	$ 12.6	$ (395.0)	$ 3,070.0
Segment profit (loss)	$ (32.0)	$ 147.4	$ 51.5	$ 110.1	$ (8.7)	$ —	$ 268.3
Less:							
Equity earnings	.7	3.8	2.9	4.2	—	—	11.6
Loss from investments	—	(.3)	—	(.2)	(6.5)	—	(7.0)
Intercompany interest rate swap loss	(21.6)	—	—	—	—	—	(21.6)
Segment operating income (loss)	$ (11.1)	$ 143.9	$ 48.6	$ 106.1	$ (2.2)	$ —	285.3
General corporate expenses							(32.0)
Consolidated operating income							$ 253.3

The following table reflects total assets by reporting segment.

	Total Assets	
	March 31, 2005	December 31, 2004
	(Millions)	
Power (1)	$ 10,930.6	$ 8,204.1
Gas Pipeline	7,514.2	7,651.8
Exploration & Production	5,917.6	5,576.4
Midstream Gas & Liquids	4,301.7	4,211.7
Other	3,562.4	3,584.0
Eliminations	(5,805.7)	(5,248.6)
	26,420.8	23,979.4
Discontinued operations	13.3	13.6
Total	$ 26,434.1	$ 23,993.0

(1) The increase in Power's total assets is primarily due to an increase in derivative assets as a result of increases in natural gas prices on existing purchases.

14. Recent accounting standards

In December 2004, the Financial Accounting Standards Board (FASB) issued revised SFAS No. 123, “Share-Based Payment.” The Statement requires that compensation costs for all share-based awards to employees be recognized in the financial statements at fair value. The Statement, as issued by the FASB, was to be effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. However, on April 15, 2005, the Securities and Exchange Commission (SEC) adopted a new rule which amends the compliance dates for revised SFAS No. 123. The rule allows implementation of the Statement at the beginning of the next fiscal year that begins after June 15, 2005. We intend to adopt the revised Statement as of January 1, 2006.

In March 2005, the FASB issued a Staff Position (FSP) on a previously issued Interpretation (FIN). FSP FIN 46(R)-5, “Implicit Variable Interests under the FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*”, states that a reporting enterprise must consider implicit variable interests when applying the provisions of FIN 46(R). The FSP is effective for the interim reporting period beginning April 1, 2005. We have evaluated this FSP and believe it does not have a material impact on our consolidated financial position and results of operations.

In March 2005, the FASB issued FIN 47, “Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143.” The Interpretation clarifies that the term *conditional asset retirement obligation*, as used in SFAS No. 143, “Accounting for Asset Retirement Obligations,” refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The effective date of this Interpretation is no later than the end of the fiscal year ending after December 15, 2005. We are assessing the impact of this Interpretation on our Consolidated Financial Statements and believe the effect will not be material.

15. Subsequent events

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. All of the units will be sold by Williams Partners L.P.

Williams Partners L.P. was formed to engage principally in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. Williams Partners L.P. will own a 40% equity investment in the Discovery gathering, transportation, processing and NGL fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50% interest in an NGL fractionator near Conway, Kansas.

ITEM 2

Management's Discussion and Analysis of Financial Condition and Results of Operation

Recent events and company outlook

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2004, we enter 2005 having completed the key components of our restructuring plan and in a position to shift our focus to growth. Our Plan for 2005 includes the following objectives:

- increase focus and disciplined EVA®-based investment in natural gas businesses;
- continue to steadily improve credit ratios and rating with the goal of achieving investment grade ratios;
- continue to reduce risk and liquidity requirements while maximizing cash flow in the Power segment;
- maintain liquidity from cash and revolving credit facilities of at least $1 billion; and
- generate sustainable growth in EVA® and shareholder value.

During the first quarter of 2005, we continued to improve our credit ratios. In January, we retired $200 million of debt which matured January 15, 2005. On February 16, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. All of the units will be sold by Williams Partners L.P.

General

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the consolidated financial statements and notes in Item 1 reflect the results of operations, financial position and cash flows through the date of sale, as applicable, of the following components as discontinued operations (see Note 4 of Notes to Consolidated Financial Statements):

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and
- our straddle plants in western Canada, previously part of the Midstream segment.

During fourth-quarter 2004, we reclassified the operations of Gulf Liquids to continuing operations within our Midstream segment in accordance with EITF 03-13, which was issued in the fourth quarter. Under the provisions of EITF 03-13, Gulf Liquids activities no longer qualified for reporting as discontinued operations, based on management's expectation that we will continue to have significant commercial activity with the disposed entity. The operations of Gulf Liquids were reclassified to continuing operations within our Midstream segment. All periods presented reflect this reclassification.

At March 31, 2005, the operations of Gulf Liquids are classified as held for sale and are included in Other current assets and Accrued liabilities on the Consolidated Balance Sheet. The Gulf Liquids assets and liabilities are not material to the Consolidated Balance Sheet. We are currently negotiating purchase and sale agreements related to the sale of these assets and we expect the sale of the operations to close by the end of the second quarter of 2005.

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1 of this document and our 2004 Annual Report on Form 10-K.

Management's Discussion & Analysis (Continued)

Results of operations

Consolidated overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2005 compared to the three months ended March 31, 2004. The results of operations by segment are discussed in further detail following this Consolidated overview discussion.

	Three months ended March 31, 2005	Three months ended March 31, 2004	% Change from 2004 *
	(Millions)		
Revenues	$ 2,954.0	$ 3,070.0	-4%
Costs and expenses:			
Costs and operating expenses	2,390.3	2,690.9	+11%
Selling, general and administrative expenses	73.5	85.5	+14%
Other (income) expense — net	(1.8)	8.3	NM
General corporate expenses	28.0	32.0	+13%
Total costs and expenses	2,490.0	2,816.7	+12%
Operating income	464.0	253.3	+83%
Interest accrued — net	(163.6)	(239.3)	+32%
Interest rate swap loss	—	(8.1)	+100%
Investing income	31.0	10.4	+198%
Minority interest in income of consolidated subsidiaries	(5.2)	(4.8)	-8%
Other income — net	5.5	.8	NM
Income from continuing operations before income taxes	331.7	12.3	NM
Provision for income taxes	129.5	12.3	NM
Income from continuing operations	202.2	—	NM
Income (loss) from discontinued operations	(1.1)	9.9	NM
Net income	$ 201.1	$ 9.9	NM

* + = Favorable Change; – = Unfavorable Change; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Three Months Ended March 31, 2005 vs. Three Months Ended March 31, 2004

The $116 million decrease in Revenues is due primarily to decreased revenues at Power primarily resulting from lower power sales volumes and the absence of crude and refined products activity, partially offset by increased unrealized mark-to-market gains. Partially offsetting the decrease at Power was an increase in revenues at Midstream and Exploration & Production associated with higher commodity prices and increased volumes.

The $300.6 million decrease in Costs and operating expenses is due primarily to decreased costs and operating expenses at Power, partially offset by increased costs and operating expenses at Midstream. The decrease at Power is due primarily to lower power purchase volumes and a decrease in crude and refined products costs.

The $12 million decrease in Selling, general and administrative (SG&A) expenses is due primarily to an accounting correction at Transco related to an overstatement of expense in prior years and lower reimbursable costs (offset in revenues).

Other (income) expense — net, within operating income, in 2005 includes:

- a $4.6 million accrual for a regulatory settlement at Power;
- a $7.9 million gain on the sale a non-core undeveloped leasehold position in Colorado at Exploration & Production; and
- $3.7 million of gains from the sale of Exploration & Production's securities, invested in a coal seam royalty trust, which were purchased for resale.

Other (income) expense — net, within operating income, in 2004 includes a $6.1 million charge at Power related to the sale of receivables to Bear Stearns.

The $4 million decrease in General corporate expense is due primarily to lower third-party costs associated with cost reduction and compliance activities and lower franchise tax expense.

The $75.7 million decrease in Interest accrued — net is due primarily to lower average borrowing levels in first-quarter 2005 as compared to first-quarter 2004.

In 2004, we entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio. We terminated all interest-rate derivatives in the fourth quarter of 2004. The change in market value of these swaps was an unfavorable $8.1 million in the first quarter of 2004.

The $20.6 million increase in Investing income is due primarily to:

- $7.7 million higher equity earnings from Gulfstream;
- $4.9 million income from certain international cost-based investments;
- the absence in 2005 of $6.5 million net unreimbursed Longhorn recapitalization advisory fees recognized in 2004; and
- the absence in 2005 of $3.6 million of impairments of certain international cost-based investments during 2004.

Partially offsetting these increases are $5.5 million of equity losses related to Longhorn operations in first-quarter 2005.

Provision for income taxes increased by $117.2 million due primarily to higher pre-tax income in 2005. The effective income tax rate for 2005 is greater than the federal statutory rate due primarily to the effect of state income taxes and an accrual for income tax contingencies partially offset by lower net foreign operations. The effective income tax rate for 2004 is significantly greater than the federal statutory rate due primarily to the effect of state income taxes, net foreign operations and an accrual for income tax contingencies.

The $11 million decrease in Income (loss) from discontinued operations is primarily due to the absence in 2005 of income from the Canadian straddle plants, which were sold subsequent to first-quarter 2004. Also contributing to the decrease is the absence in 2005 of gains on the sale of the Alaska refinery and related assets and our interest in Williams Energy Partners, both of which were sold in first-quarter 2004.

Results of operations — segments

We are currently organized into the following reporting segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations formerly included in the previously reported International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 13 of Notes to Consolidated Financial Statements).

Power

Overview of three months ended March 31, 2005

Power's operating results for the first quarter of 2005 were significantly influenced by the effect of price changes on power and natural gas derivative contracts, which caused forward unrealized mark-to-market gains.

In the first quarter of 2005, Power continued to focus on its objectives of minimizing financial risk, maximizing cash flow, meeting contractual commitments, executing new contracts to hedge its portfolio and providing functions that support our natural gas businesses.

Key factors that may influence Power's financial condition and operating performance include the following:

- prices of power and natural gas, including changes in the margin between power and natural gas prices;
- changes in market liquidity, including changes in the ability to effectively hedge the portfolio;
- changes in power and natural gas price volatility;
- changes in interest rates;
- changes in the regulatory environment;
- changes in power and natural gas supply and demand; and
- the inability of counterparties to perform under contractual obligations due to their own credit constraints.

Outlook for the remainder of 2005

For the remainder of 2005, Power intends to service its customers' needs while increasing the certainty of cash flows from its long-term contracts.

As Power continues to apply hedge accounting in 2005, its future earnings may be less volatile. However, not all of Power's derivative contracts qualify for hedge accounting. Power will continue to report changes in the fair value of those remaining non-hedge contracts in earnings as unrealized gains or losses. In addition, the ineffective portion of the change in the forward fair value of qualifying hedges will also be reported in earnings. Because the derivative contracts qualifying for hedge accounting were previously marked to market through earnings prior to their being designated as cash flow hedges, the amounts recognized in future earnings under hedge accounting will not necessarily align with the expected cash flows to be realized from the settlement of those derivatives. For example, to the extent that future earnings will reflect losses from underlying transactions that have been hedged by the derivatives, the corresponding offsetting gains from the hedges have already been recognized in prior periods under mark-to-market accounting. However, cash flows from Power's portfolio continue to reflect the net amount from both the hedged transactions and the hedges.

Even with the adoption of hedge accounting, some variability in Power's earnings will remain as a result of:

- market movements of commodity-based derivatives held for trading purposes or which did not qualify for hedge accounting; and
- ineffectiveness of cash flow hedges primarily caused by locational differences between the hedging derivative and the hedged item or changes in the creditworthiness of counterparties.

The fair value of Power's tolling, full requirements, transportation, storage and transmission contracts are not reflected in the balance sheet since these contracts are not derivatives. Some of these contracts have a significant negative estimated fair value and could also result in future operating gains or losses as a result of the volatile nature of energy commodity markets. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future operations.

Three months ended March 31, 2005 vs. three months ended March 31, 2004

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Realized revenues	$ 1,843.8	$ 2,251.1
Net forward unrealized mark-to-market gains	221.1	23.7
Segment revenues	2,064.9	2,274.8
Cost of sales	1,925.0	2,276.2
Gross margin	139.9	(1.4)
Operating expenses	5.3	6.4
Selling, general and administrative expenses	16.0	16.2
Other income (expense) — net	(4.5)	(8.0)
Segment profit (loss)	$ 114.1	$ (32.0)

The $209.9 million decrease in revenues includes a $407.3 million decrease in realized revenues, partially offset by a $197.4 million increase in net forward unrealized mark-to-market gains.

Realized revenues represent 1) revenue from the sale of commodities or completion of energy-related services, and 2) gains and losses from the net financial settlement of derivative contracts. The $407.3 million decrease in realized revenues is primarily due to a $315 million decrease in power and natural gas realized revenues and a $108 million decrease in crude and refined products realized revenues, partially offset by the absence in 2005 of a $16 million realized loss from the interest rate portfolio.

Power and natural gas realized revenues decreased primarily due to a 37 percent decrease in power sales volumes, partially offset by a seven percent increase in average power sales prices. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated. Crude and refined products revenues decreased due to the sale of the refined products business in 2004. The absence of activity in the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. In first-quarter 2004, a decrease in interest rates caused a realized loss on interest rate derivatives.

Net forward unrealized mark-to-market gains represent changes in the fair value of derivative contracts with a future settlement or delivery date. The $197.4 million increase in net forward unrealized gains is primarily due to a $170 million increase associated with power and gas contracts and the absence in 2005 of the $28 million unrealized loss on the interest rate portfolio in 2004. The increase in power and gas primarily results from a greater increase in natural gas forward prices in first-quarter 2005 than in first-quarter 2004. Cash flow hedge accounting, which was prospectively applied to certain of Power's forecasted transactions beginning October 1, 2004, partially offsets the impact of natural gas price increases. Net unrealized gains of $84 million related to the effective portion of the hedges are reported in Accumulated other comprehensive loss in first-quarter 2005. Also in first-quarter 2005, Power recognized losses of $6.8 million representing a correction of unrealized losses associated with a prior year. The absence in 2005 of the unrealized loss on the interest rate portfolio is due to the termination and liquidation of all remaining interest-rate derivatives in fourth-quarter 2004. A decrease in forward interest rates caused unrealized losses in the interest rate portfolio in first-quarter 2004.

The $351.2 million decrease in Power's cost of sales is primarily due to a decrease in power and natural gas costs of $244 million and a decrease in crude and refined products costs of $107 million. Power and natural gas costs decreased primarily due to a 36 percent decrease in power purchase volumes, partially offset by a 15 percent increase in power purchase prices. Costs in first-quarter 2004 also reflect a $13 million payment made to terminate a non-derivative power sales contract. Crude and refined products costs decreased due to the sale of the refined products business in 2004.

SG&A expenses in first-quarter 2004 include a $6 million reduction of allowance for bad debts resulting from a 2004 settlement with certain California utilities.

Other (income) expense — net in first-quarter 2005 includes a $4.6 million accrual for a regulatory settlement. Other (income) expense — net in first-quarter 2004 includes a $6.1 million charge related to the sale of certain receivables to a third party.

The $146.1 million increase in segment profit is primarily due to an increase in forward unrealized mark-to-market gains largely associated with larger increases in forward natural gas prices in the first quarter of 2005 compared to the same period in 2004. Also contributing to the increase in segment profit is the absence of realized losses from the interest rate portfolio, which was liquidated in the fourth quarter of 2004.

Gas Pipeline

Overview of three months ended March 31, 2005

Effective January 2005, Duke Energy Trading and Marketing, LLC (Duke) terminated its firm transportation agreement related to Northwest Pipeline's Grays Harbor lateral. In January 2005, Duke paid Northwest Pipeline $94 million toward the contractually required termination payment. Duke and Northwest Pipeline have not agreed on the amount of the obligation. Northwest Pipeline's net book value of the related assets is $88 million. Northwest Pipeline has deferred the $6 million difference between the proceeds and net book value pending resolution of the disputed termination payment.

In February 2005, Gulfstream placed into service its 110-mile Phase II natural gas pipeline extension, expanding its reach across Florida and facilitating the increase of long-term firm service by 350 million cubic feet per day.

Operating results for the first quarter of 2005 include approximately $13 million of credits to expenses, reflected as a $7 million reduction of Cost and operating expenses and a $6 million reduction of SG&A expenses. These credits are corrections of the carrying value of certain liabilities that were recorded in prior periods. Based on a review by management, these liabilities are no longer required and the reversal of amounts should have occurred in prior periods. Our management concluded that the effect of the previous accounting treatment is not material to prior periods, expected 2005 results or trend of earnings.

Outlook for the remainder of 2005

Central New Jersey Expansion Project

In February 2005, Transco received authorization from the FERC to construct and operate the Central New Jersey Expansion Project on its natural gas pipeline system. The expansion will provide an additional 105 Mdt/d of firm natural gas transportation service in Transco's northeastern market area. The estimated cost of the project is $13 million. The construction is scheduled to begin in the summer of 2005 and is expected to be placed into service in November 2005.

Three months ended March 31, 2005 vs. three months ended March 31, 2004

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Segment revenues	$ 335.3	$ 359.0
Segment profit	$ 167.4	$ 147.4

The $23.7 million, or seven percent, decrease in Gas Pipeline revenues is due primarily to $11 million lower revenues associated with reimbursable costs, which are passed through to customers (offset in costs and operating expenses and general and administrative expenses), $5 million lower revenues due to the termination of the Grays Harbor agreement, as discussed above, and $4 million lower revenues from exchange imbalance settlements (offset in costs and operating expenses).

Table of Contents

Costs and operating expenses decreased $23 million, or 12 percent, due primarily to the reversal of $7 million of accruals noted above, $6 million lower recovery of reimbursable costs which are passed through to customers (offset in revenues), and $4 million lower gas exchange imbalance settlements (offset in revenues).

General and administrative costs decreased $14 million, or 42 percent, due primarily to the reversal of $6 million of accruals noted above and $6 million lower reimbursable costs (offset in revenues).

The $20 million, or 14 percent, increase in segment profit, which includes equity earnings and income (loss) from investments, is primarily due to approximately $13 million of income related to the reversal of liabilities (noted above) and $8 million higher equity earnings related to our investment in Gulfstream. The increase in Gulfstream earnings reflects the benefit of a $4.6 million construction fee realized in association with the completion of the Phase II expansion project and additional revenue from an associated contract.

Exploration & Production

Overview of three months ended March 31, 2005

Total average daily production for the quarter ending March 31, 2005 is approximately 614 million cubic feet of gas equivalent (MMcfe) compared to 502 MMcfe for the same period in 2004**.** Our first-quarter domestic average daily production volumes have increased 24 percent from the same period in 2004, increasing from 457 MMcfe to 568 MMcfe, respectively. The increase is directly related to our increased targeted drilling program, primarily within the Piceance basin. The increased production, as well as an increase in net realized average prices, resulted in increased revenue for the first quarter of 2005 as compared to the same period in the prior year. Operating costs also increased as a result of servicing an increased number of wells drilled in 2004. However, these costs are fairly flat when compared on a per unit of production basis.

Outlook for the remainder of 2005

Our expectations for the remainder of the year include the following.

- A continuing development drilling program in our key basins with increased activity in the Piceance and Powder River basins with associated planned capital expenditures projected in the range of approximately $375 million to $450 million for the remainder of 2005.

- Achieving a fifteen percent increase in average daily domestic production levels from the beginning of the year through the end of 2005.

Approximately 284 MMcfe per day of our remaining 2005 domestic production is hedged at prices that average $4.01 per MMcfe at a basin level. In addition, we have 50 MMcfe production per day hedged in NYMEX collar agreements that have an average floor price of $6.75 per MMcfe and an average ceiling price of $8.50 per MMcfe.

In March 2005, we entered into a contract for the operation of ten new drilling rigs, each for a three year term. The additional rigs will allow us to accelerate our pace of development in the Piceance basin through both deployment of the additional rigs and also as a result of the drilling and operational efficiencies the rigs are designed to deliver. We expect to deploy one new rig each month, for ten months, beginning in November 2005.

Three months ended March 31, 2005 vs. three months ended March 31, 2004

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Segment revenues	$ 249.0	$ 165.2
Segment profit	$ 103.7	$ 51.5

The $83.8 million, or 51 percent, increase in Exploration & Production revenues is primarily due to a $77 million increase in domestic production revenues reflecting higher production volumes and net realized average prices, which include the effect of hedge positions. The increase in domestic production revenues reflects $48 million higher revenues associated with a 31 percent increase in net realized average prices for production sold and $29 million higher revenues associated with a 24 percent increase in average daily production volumes. The remainder of the increase reflects an increase of $12 million higher revenues from gas management activities.

The increase in production volumes primarily reflects an increase in the number of producing wells resulting from our successful 2004 and first-quarter 2005 drilling programs. We expect production volumes to continue to increase for the remainder of 2005 as our development drilling program continues. The higher net realized average prices reflect the benefit of lower hedging levels than the prior period coupled with higher market prices for natural gas.

To manage the risk and volatility associated with the ownership of producing gas properties, we enter into derivative forward sales contracts, which economically lock in a price for a portion of our future production. During the first quarter of 2005, we had approximately 53 percent of our domestic production hedged at prices that average $3.95 per MMcfe at a basin level compared to 83 percent hedged at $3.72 per MMcfe for the same period in 2004. In addition, during the first quarter of 2005 we had 50 MMcfe of production per day hedged in NYMEX collar arrangements that had an average floor price of $7.50 per MMcfe and an average ceiling price of $10.49 per MMcfe.

Total costs and expenses increased $32 million, primarily due to the following:

- $12 million higher gas management expenses associated with the higher revenues from gas management activities mentioned above;
- $16 million higher depreciation, depletion and amortization expense, primarily due to higher production volumes and increased capitalized drilling costs;
- $5 million higher lease operating and facilities expenses associated with the higher number of producing wells;
- $5 million higher operating taxes primarily as a result of increased market prices and production volumes sold; and
- $9 million higher other income due to a $7.9 million gain on the sale of an undeveloped leasehold position in Colorado.

The $52.2 million increase in segment profit is due primarily to increased revenues from higher volumes and higher average prices, partially offset by higher expenses discussed above.

Midstream Gas & Liquids

Overview of three months ended March 31, 2005

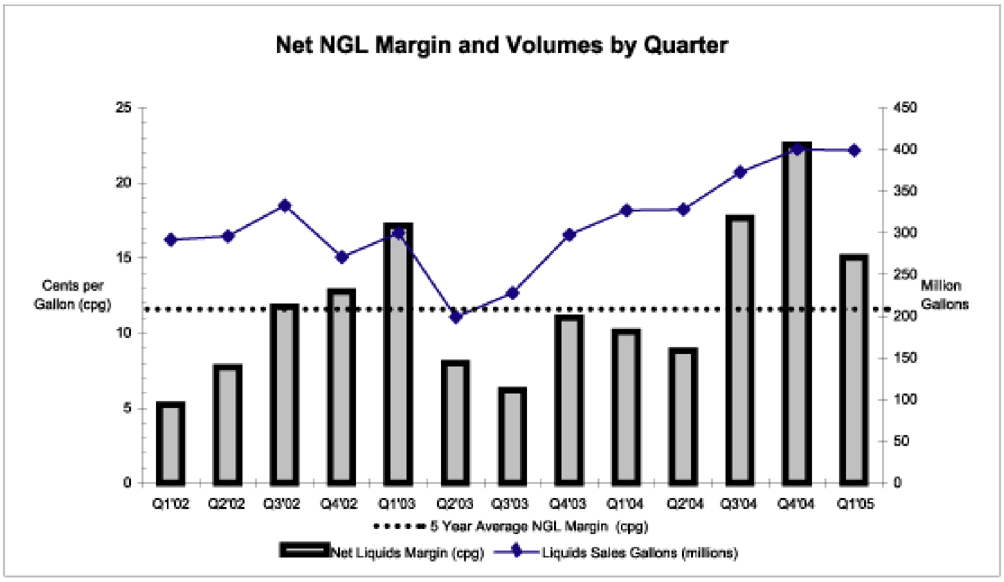
In 2005, our ongoing strategy is to safely operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. Our business is focused on consistently attracting new volumes to our assets by providing customers highly reliable service.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. All of the units will be sold by Williams Partners L.P.

Management's Discussion & Analysis (Continued)

Williams Partners L.P. was formed to engage principally in the business of gathering, transporting and processing natural gas and fractionating and storing natural gas liquids. Williams Partners L.P. will own a 40% equity investment in the Discovery gathering, transportation, processing and NGL fractionation system; the Carbonate Trend sour gas gathering pipeline; three integrated NGL storage facilities near Conway, Kansas; and a 50% interest in an NGL fractionator near Conway, Kansas.

Favorable Commodity Price Margins — Despite a decline from levels realized in the previous two quarters, our natural gas liquids (NGL) per unit margins earned at our gas processing plants exceeded the historical five-year annual average. This above average level is largely the result of a significant increase in crude oil prices and an increased demand for petrochemical feedstocks such as ethane and propane. As indicated in the graph below, our quarterly margins exceeded the historical five-year annual average for the last three quarters. As a result of continued favorable NGL margins and high production volumes, our gas processing facilities produced positive financial results and operated at near capacity during the first quarter of 2005. Our olefins businesses also benefited from favorable commodity prices associated with additional demand for ethylene and propylene.



Outlook for the remainder of 2005

The following factors could impact our business in the remaining quarters of 2005 and beyond.

- As evidenced in recent years, natural gas and crude oil markets are highly volatile. Although NGL margins earned at our gas processing plants in the last three quarters were very favorable, we expect margins in the last half of 2005 to trend downward towards historical averages. NGL production volumes at our facilities are expected to be at or above levels of previous years due to continued strong drilling activities in our core basins.

- Our olefins margins were also favorable in the last three quarters. While we believe this trend should continue in the near term, olefins margins are highly volatile and levels in the last three quarters are not necessarily indicative of levels expected for the remainder 2005. Additionally, a fire at a Canadian oil sands facility that supplies us with off-gas feedstock reduced our throughput in the first quarter of 2005. We expect this reduced throughput to continue through late 2005, partially offsetting any favorable margins.

- We expect additional revenues from our Devil's Tower facilities in late 2005 as completed wells in the Triton and Goldfinger prospects begin to flow new production volumes.

- We expect continued growth in the deepwater areas of the Gulf of Mexico to contribute to, and become a larger component of, our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our proportionate exposure to commodity price risks.

- We are planning to invest in an expansion of the Wamsutter gathering system in 2005 and 2006 to keep pace with the increased demand for our gathering and processing services.

- We continue efforts to sell our Gulf Liquids refinery off-gas and propylene splitting business in Louisiana and anticipate closing the sale of the refinery off-gas business in the second quarter of 2005.

Three months ended March 31, 2005 vs. three months ended March 31, 2004

	Three months ended March 31, 2005	Three months ended March 31, 2004
	(Millions)	
Segment revenues	$ 807.0	$ 631.8
Segment profit (loss)		
Domestic Gathering & Processing	$ 100.2	$ 90.3
Venezuela	22.0	21.9
Other	22.0	11.5
Unallocated general and administrative expense	(15.6)	(13.6)
Total	$ 128.6	$ 110.1

In order to provide additional clarity, our management discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as "Unallocated general and administrative expense" above. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion. Both periods presented reflect this change.

The $175.2 million increase in Midstream's revenues is due primarily to favorable commodity prices and higher sales volumes related to our gas processing business. Revenues associated with production of NGLs increased $89 million, of which $47 million is due to higher NGL prices and $42 million is due to higher volumes. Crude marketing revenues increased $62 million as a result of the start up of a deepwater pipeline in the second quarter of 2004. In addition, the marketing of NGLs on behalf of customers increased $25 million as a result of both higher prices and volumes.

Costs and operating expenses increased $156 million primarily in support of higher sales noted above. A significant component of this increase is $61 million in higher costs related to the increased production of NGLs. Approximately $54 million of this increase is due to higher production volumes and higher prices for natural gas, while the remainder is related to additional transportation fees. Similar to the impact to revenues, total costs and operating expenses also increased $62 million due to higher crude marketing purchases and $25 million related to the marketing of NGLs on behalf of customers.

The $18.5 million increase in Midstream segment profit is primarily due to higher NGL and olefins production margins, partially offset by higher operating expenses. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $9.9 million increase in domestic gathering and processing segment profit includes an $18.2 million increase in the West region and partially offset by an $8.3 million decrease in the Gulf Coast region.

The $18.2 million increase in our West region's segment profit primarily resulted from higher net NGL margins, which increased $21 million compared to the first quarter of 2004. Average per unit NGL margins increased 57 percent and comprised $16 million of the increase in NGL margins. As a result of the higher spread between the prices of NGLs and natural gas, our West plants operated at near capacity and produced 25 percent higher volumes, comprising the remaining $5 million increase in NGL margins.

The $8.3 million decrease in our Gulf Coast region’s segment profit is due to higher operating expenses partially offset by higher net NGL margins. The significant components of the net decline include the following.

- Segment profit from our deepwater assets declined $4 million largely as a result of a product leak on a customer’s pipeline resulting in volumes being shut in at our Canyon Station production handling facilities during January and much of February.

- Segment profit from our Gulf gathering assets declined $5 million largely due to timing of maintenance projects in 2005 versus 2004.

- Net NGL margins at our Gulf Coast gas processing plants increased $6 million due to higher per unit margins.

Venezuela: Segment profit for our Venezuela assets for the first quarter of 2005 was virtually unchanged from that earned in the first quarter of 2004.

Other: The $10.5 million increase in segment profit in our other businesses is due to higher olefins production and NGL marketing margins, partially offset by lower fee revenue.

- Combined margins from our olefins businesses improved $11 million, primarily due to stronger per unit margins indicative of a rising crude oil market and stronger demand. The higher olefins margins were partially offset by approximately $4 million in lower fee revenue due to the sale of the ethylene distribution system in the fourth quarter of 2004 and slightly lower production volumes.

- Net margins from the marketing of NGLs increased $4 million largely due to the impact of higher market prices.

Unallocated general and administrative expense: The increase in unallocated general and administrative expense is primarily due to increased professional fees.

Other

	Three months ended March 31,	
	2005	2004
	(Millions)	
Segment revenues	$ 7.0	$ 12.6
Segment loss	$ (4.1)	$ (8.7)

Other segment loss for 2005 includes $5.5 million of equity losses related to our investment in Longhorn Partners Pipeline, L.P. (Longhorn). Other segment loss for 2004 includes $6.5 million of net unreimbursed advisory fees related to the capitalization of Longhorn in February 2004.

On April 1, 2005, we completed a contract to transfer our Longhorn operating agreement to a new operator in exchange for payments of approximately $285,000 a month, adjusted for inflation, over the next seven years. The transfer became effective in the second quarter.

Fair value of trading and non-trading derivatives

The table below reflects the fair value of derivatives held for trading purposes as of March 31, 2005. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

Net Assets (Liabilities)
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 36-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	Net Fair Value
$(5)	$2	$(1)	$(1)	$(5)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of non-trading derivative contracts. Non-trading derivative contracts are those that hedge or could possibly hedge on an economic basis forecasted transactions associated with Power's long-term structured contract position and owned generation, Exploration & Production's forecasted sales of natural gas production, as well as the activities of our other segments. As a result of our decision to retain the Power business, in the fourth quarter of 2004 we designated a portion of the existing derivatives as SFAS 133 cash flow hedges. Many of these non-trading derivatives had an existing fair value prior to their designation as cash flow hedges. Certain other of Power's derivatives have not been designated as, or do not qualify as, SFAS 133 hedges. We also hold certain derivative contracts, which also qualify as SFAS 133 cash flow hedges, that primarily hedge Exploration & Production's forecasted natural gas sales. The table below reflects the fair value of derivatives held for non-trading purposes as of March 31, 2005. Of the total fair value of non-trading derivatives, SFAS 133 cash flow hedges had a net asset value of $51.5 million as of March 31, 2005, which includes the fair value of the derivatives upon their designation as SFAS 133 cash flow hedges.

Net Assets (Liabilities)
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 36-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(37)	$95	$120	$44	$5	$227

Counterparty credit considerations

We include an assessment of the risk of counterparty non-performance in our estimate of fair value for all contracts. Such assessment considers 1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investors Service, 2) the inherent default probabilities within these ratings, 3) the regulatory environment that the contract is subject to and 4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At March 31, 2005, we held collateral support of $381 million. We also enter into netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts as of March 31, 2005 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 700.2	$ 758.3
Energy marketers and traders	1,599.1	4,650.5
Financial institutions	2,893.8	2,895.4
Other	1.5	17.0
	$ 5,194.6	8,321.2
Credit reserves		(29.3)
Gross credit exposure from derivatives		$ 8,291.9

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of March 31, 2005 is summarized below.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 150.9	$ 170.1
Energy marketers and traders	362.8	592.7
Financial institutions	278.9	279.0
Other	1.5	3.0
	$ 794.1	$ 1,044.8
Credit reserves		(29.3)
Net credit exposure from derivatives(b)		$ 1,015.5

(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum Standard & Poor's rating of BBB— or Moody's Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements.

Financial condition and liquidity

Liquidity

Overview

In January, we retired $200 million of 6.125% notes which matured January 15, 2005. On February 16, 2005, the holders of the remaining 10.9 million equity forward contracts associated with the FELINE PACS units exercised contracts to purchase one share of our common stock for $25 a share, resulting in cash proceeds of approximately $273 million. The remaining notes associated with the FELINE PACS units totaling approximately $73 million are due February 16, 2007.

In January 2005, our two unsecured revolving credit facilities were terminated and replaced with two new facilities. The two new facilities do not include most of the restrictive covenants of the previous two facilities, including the fixed charge ratio. The new facilities also no longer limit quarterly dividends, asset sales, and the incurrence of additional indebtedness and issuance of disqualified stock.

Sources of liquidity

Our liquidity is derived from both internal and external sources. Certain of those sources are available to us (at the parent level) and others are available to certain of our subsidiaries.

At March 31, 2005, we have the following sources of liquidity from cash and cash equivalents:

- cash-equivalent investments at the corporate level of $861 million as compared to $735 million at December 31, 2004; and
- cash and cash-equivalent investments of various international and domestic entities of $349 million, as compared to $195 million at December 31, 2004.

At March 31, 2005, we have capacity of $8 million available under our two unsecured revolving credit facilities totaling $500 million, compared to $28 million at December 31, 2004. These facilities provide for both borrowings and letters of credit, but are used primarily for issuing letters of credit.

At March 31, 2005, we also have capacity of $820 million available under our $1.275 billion secured revolving credit facility compared to $853 million at December 31, 2004. Northwest Pipeline and Transco each have access to $400 million under the facility, which is secured by certain Midstream assets and guaranteed by Williams Gas Pipeline Company, LLC, the parent company of Transco and Northwest Pipeline.

We have an effective shelf registration statement with the Securities and Exchange Commission that authorizes us to issue an additional $2.2 billion of a variety of debt and equity securities. In addition, our wholly owned subsidiaries, Northwest Pipeline and Transco, also have outstanding registration statements filed with approximately $350 million of shelf availability remaining under these registration statements at March 31, 2005. The ability of Northwest Pipeline to utilize these registration statements for debt securities is restricted by certain covenants of its debt agreements. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets.

During the first three months of 2005, we satisfied liquidity needs with:

- $304.4 million in cash generated from cash flows of continuing operating activities;
- approximately $273 million proceeds from the issuance of 10.9 million shares of common stock purchased under the FELINE PACS equity forward contracts;
- approximately $87.9 million from a contract termination payment; and
- approximately $54.7 million proceeds from the sale of the WilTel Note.

Credit ratings

One of our objectives for 2005 is to continue the improvement in our financial ratios, with the goal of achieving ratios comparable to investment grade rated companies. If the improvement in our ratios continues, our credit ratings may improve. However, a decline in our financial ratios, or other adverse events, could result in a ratings decline.

Off-balance sheet financing arrangements and guarantees of debt or other commitments to third parties

In January 2005, we terminated our two unsecured revolving credit facilities totaling $500 million and replaced them with two new facilities that contain similar terms but fewer restrictions (see Note 9 of Notes to the Consolidated Financial Statements).

We have various guarantees which are disclosed in Note 11 of Notes to Consolidated Financial Statements. We do not believe these guarantees, or the possible fulfillment of them, will negatively impact our liquidity.

Operating activities

The improvement in cash flow from continuing operating activities in 2005 is due primarily to an increase in Income from continuing operations, resulting from higher gas production volumes and net average realized prices for production sold and improved NGL margins.

In the first quarter of 2004, we recognized net cash used by operating activities of discontinued operations in the Consolidated Statement of Cash Flows of $52.9 million. Included in this amount was approximately $70 million in use of funds related to the timing of settling working capital issues of the Alaska refinery and related assets. In the second quarter of 2004, we received the proceeds from the collection of approximately $58 million in trade receivables related to the Alaska refinery and related assets.

Financing activities

In the first quarter of 2005, our Transco subsidiary retired $200 million of 6.125 percent unsecured notes due January 15, 2005.

As discussed above, in the first quarter of 2005 we received approximately $273 million in proceeds from the issuance of common stock purchased under the FELINE PACS equity forward contracts.

In the first quarter of 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004.

Dividends paid on common stock are currently $.05 per common share on a quarterly basis and totaled $28.5 million for the three months ended March 31, 2005. For the three months ended March 31, 2004, dividends paid on common stock were $.01 per share on a quarterly basis and totaled $5.2 million. A covenant under our former $500 million revolving credit facilities limited our quarterly common stock dividends to not more than $.05 per common share. The covenant was removed when the facilities were terminated and replaced on January 20, 2005.

Investing activities

During the first quarter of 2005, capital expenditures totaled approximately $222.9 million and were primarily related to our Exploration & Production segment's expansion projects, mostly in the Piceance basin.

In January 2005, we received approximately $54.7 million proceeds from the sale of our WilTel Note.

In March 2005, we recorded an $87.9 million contract termination payment. This amount was received by Northwest Pipeline as a result of a contract termination. Northwest Pipeline entered into a contract to build a pipeline and supply gas to a proposed power plant. The customer subsequently terminated the contract and thus was required to reimburse Northwest Pipeline for the net book value of the pipeline.

During the first quarter of 2004, we purchased $235.9 million of restricted investments comprised of U.S. Treasury notes and received proceeds of $331.2 million on the scheduled maturity of certain of this type investment. We made these purchases to satisfy the 105 percent cash collateralization requirement in our $800 million revolving credit facility. The facility was terminated on May 3, 2004, after we obtained the $1 billion secured revolving credit facility, which was subsequently amended in August 2004 to the current level of $1.275 billion.

During February 2004, we participated in a recapitalization plan completed by Longhorn. As a result of this plan, we received approximately $58 million in repayment of a portion of our advances to and deferred payments from Longhorn and converted the remaining advances, including accrued interest, into subordinated equity interests in Longhorn. The $58 million received is included in Proceeds from dispositions of investments and other assets.

In the first quarter of 2004, we received $279 million in proceeds from the sale of the Alaska refinery, retail and pipeline and related assets.

Contractual obligations

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2004, we had certain contractual obligations at December 31, 2004, with various maturity dates, related to the following:

- long-term debt;
- operating leases;
- purchase obligations; and
- other long-term liabilities, including physical and financial derivatives.

During the first quarter of 2005, the amount of our contractual obligations changed significantly due to the following.

- Our Transco subsidiary retired $200 million of 6.125 percent notes due January 15, 2005.
- During first-quarter 2005, Power's physical and financial derivatives increased by approximately $1.1 billion. The increase is due primarily to natural gas price increases on existing purchases and the addition of new contracts in the first quarter.
- In March 2005, we entered into a contract for the operation of ten newly constructed drilling rigs, with each rig carrying a three-year commitment. Expected delivery of the first rig is November 2005, then one rig per month for the next nine months. The minimum contractual obligation at March 31, 2005, is $104 million associated with early termination penalties of $10.4 million per rig. The base amount of payments over the life of the contract is $192 million, and could increase to $230 million if all performance incentives are earned.

Outlook for 2005 and beyond

We entered 2005 positioned for growth through disciplined investments in natural gas businesses. During 2005, we expect to maintain liquidity from cash and revolving credit facilities of at least $1 billion. We are maintaining this level as we consider the potential impact of significant changes in commodity prices, contract margin requirements above current levels, unplanned capital spending needs and the need to meet near term scheduled debt payments. Scheduled debt maturities for the last three quarters of 2005 total approximately $31 million.

The additional rigs contracted for in March 2005 will allow us to accelerate the pace of developing our natural gas reserves in the Piceance basin through both deployment of the additional rigs and drilling and operational efficiencies the rigs are designed to deliver. Beginning in November 2005, we expect to deploy one new rig each month. As a result, we have increased our planned capital spending for Exploration & Production by $30 million in 2005 and $200 million in both 2006 and 2007.

We estimate capital and investment expenditures will total approximately $1 billion to $1.2 billion in 2005, with approximately $800 million to $1 billion to be incurred over the next nine months. Of the estimated capital expenditures for 2005, approximately $610 million to $695 million is for maintenance related projects primarily at Gas Pipeline, including pipeline replacement and Clean Air Act projects. We expect to fund capital and investment expenditures, debt payments, and working-capital requirements through cash and cash equivalents on hand and cash generated from operations, which is currently estimated to be between $1.3 billion and $1.6 billion in 2005.

On May 2, 2005, Williams Partners L.P. filed a registration statement on Form S-1 with the SEC relating to a proposed underwritten initial public offering of five million common units, representing limited partnership interests in Williams Partners L.P., plus an option for the underwriters to purchase up to an additional 750,000 common units. All of the units will be sold by Williams Partners L.P.

Based on our available cash on hand and expected cash flows from operations, we believe we have, or have access to, the financial resources and liquidity necessary to meet future cash requirements and maintain a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds.

Item 3

Quantitative and Qualitative Disclosures About Market Risk

Interest rate risk

Our interest rate risk exposure associated with the debt portfolio has not materially changed during the first quarter of 2005.

Commodity price risk

We are exposed to the impact of market fluctuations in the price of natural gas, power, crude oil, refined products and natural gas liquids as well as other market factors, such as market volatility and commodity price correlations, including correlations between crude oil and gas prices and between natural gas and power prices. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregated our derivative contracts into trading and non-trading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS No. 133 and non-derivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into to provide price risk management services to third-party customers. Only contracts that meet the definition of a derivative are carried at fair value on the balance sheet. Our value at risk for contracts held for trading purposes was approximately $1 million at March 31, 2005 and December 31, 2004.

Non-trading

Our non-trading portfolio consists of contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	• Natural gas sales
Midstream	• Natural gas purchases
Power	• Natural gas purchases • Electricity purchases • Electricity sales

The value at risk for contracts held for non-trading purposes was $34 million and $29 million at March 31, 2005 and December 31, 2004, respectively. Certain of the contracts held for non-trading purposes are accounted for as cash flow hedges under SFAS No. 133. We do not consider the underlying commodity positions to which the cash flow hedges relate in our value-at-risk model. Therefore, value at risk does not represent economic losses that could occur on a total non-trading portfolio that includes the underlying commodity positions.

Item 4

Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15(d) - (e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

First Quarter 2005 Changes in Internal Controls Over Financial Reporting

On January 1, 2005, we completed the first of a series of system implementations which are part of an enterprise initiative to move to common enterprise accounting systems. The implementation on January 1, 2005 impacted our Midstream and Power business segments and corporate functions and related primarily to an upgrade to the primary accounting system used to process, accumulate and summarize accounting information. It also included replacement of the accounting system used to maintain information for capital projects, property and depreciation and amortization records.

Other than as described above, there has been no material change that occurred during the first fiscal quarter in our Internal Controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 11 Contingent liabilities and commitments included in the Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

None.

Item 6. Exhibits

(a) The exhibits listed below are filed or furnished as part of this report:

Exhibit 12 — Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.

Exhibit 31.1 — Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2 — Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32 — Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Table of Contents

SIGNATURE

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

THE WILLIAMS COMPANIES, INC.

(Registrant)

/s/ Gary R. Belitz

Gary R. Belitz
Controller
(Duly Authorized Officer and Principal Accounting Officer)

May 5, 2005

Exhibit 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Fixed Charges
(Dollars in millions)

	Three months ended March 31, 2005
Earnings:	
Income from continuing operations before income taxes	$ 331.7
Minority interest in income of consolidated subsidiaries	5.2
Less: Equity earnings	(17.7)
Income from continuing operations before income taxes, minority interest in income of consolidated subsidiaries and equity earnings	319.2
Add:	
Fixed charges:	
Interest accrued, including proportionate share from equity-method investees	166.2
Rental expense representative of interest factor	4.6
Total fixed charges	170.8
Distributed income of equity investees	19.3
Less:	
Capitalized interest	(1.1)
Total earnings as adjusted	$ 508.2
Fixed charges	$ 170.8
Ratio of earnings to fixed charges	2.98

Exhibit 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 5, 2005

/s/ Steven J. Malcolm

Steven J. Malcolm
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 5, 2005

/s/ Donald R. Chappel

Donald R. Chappel
Senior Vice President and Chief Financial Officer
(Principal Executive Officer)

Exhibit 32

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of The Williams Companies, Inc. (the “Company”) on Form 10-Q for the period ending March 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm
Steven J. Malcolm
Chief Executive Officer
May 5, 2005

/s/ Donald R. Chappel
Donald R. Chappel
Chief Financial Officer
May 5, 2005

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.