WILLIAMS COMPANIES INC
Form 10-Q
May 03, 2007

Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2007

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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a nonaccelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ Accelerated filer o Nonaccelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.)

Yes o No þ

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, 2007
Common Stock, $1 par value	598,858,516 Shares

The Williams Companies, Inc.
Index

Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements 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.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements include, among others, statements regarding:

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Business strategy;

Estimates of proved gas and oil reserves;

Reserve potential;

Development drilling potential;

Cash flow from operations;

Seasonality of certain business segments;

Power, natural gas and natural gas liquids prices and demand.

Table of Contents

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

Availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;

Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;

The strength and financial resources of our competitors;

Development of alternative energy sources;

The impact of operational and development hazards;

Costs of, changes in, or the results of laws, government regulations including proposed climate change legislation, environmental liabilities, litigation, and rate proceedings;

Changes in the current geopolitical situation;

Risks related to strategy and financing, including restrictions stemming from our debt agreements and our lack of investment grade credit ratings;

Risk associated with future weather conditions and acts of terrorism.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item IA. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006.

Table of Contents

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

	Three months ended March 31,	
(Dollars in millions, except per-share amounts)	**2007**	**2006**
Revenues:		
Exploration & Production	$ 482.7	$ 356.0
Gas Pipeline	370.8	334.0
Midstream Gas & Liquids	995.4	979.4
Power	1,775.1	2,053.2
Other	6.8	6.9
Intercompany eliminations	(778.7)	(702.0)
Total revenues	2,852.1	3,027.5
Segment costs and expenses:		
Costs and operating expenses	2,362.7	2,588.7
Selling, general and administrative expenses	117.5	71.0
Other income net	(18.1)	(22.3)
Total segment costs and expenses	2,462.1	2,637.4
General corporate expenses	39.4	31.8
Operating income (loss):		
Exploration & Production	182.8	142.6
Gas Pipeline	140.4	127.2
Midstream Gas & Liquids	147.3	141.6
Power	(81.1)	(22.3)
Other	.6	1.0
General corporate expenses	(39.4)	(31.8)
Total operating income	350.6	358.3
Interest accrued	(173.3)	(162.8)
Interest capitalized	4.9	3.0
Investing income	43.7	46.9
Early debt retirement costs		(27.0)
Minority interest in income of consolidated subsidiaries	(14.0)	(7.1)
Other income net	2.0	8.1
Income from continuing operations before income taxes	213.9	219.4
Provision for income taxes	82.1	88.3

Income from continuing operations	131.8	131.1
Income from discontinued operations	2.2	.8
Net income	$ 134.0	$ 131.9
Basic earnings per common share:		
Income from continuing operations	$ .22	$ .22
Income from discontinued operations		
Net income	$ .22	$ .22
Weighted-average shares (thousands)	598,031	591,407
Diluted earnings per common share:		
Income from continuing operations	$ .22	$ .22
Income from discontinued operations		
Net income	$ .22	$ .22
Weighted-average shares (thousands)	611,470	607,073
Cash dividends declared per common share	$ .09	$ .075

See accompanying notes.

3

Table of Contents

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

(Dollars in millions, except per-share amounts)	March 31, 2007	December 31, 2006
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,811.2	$ 2,268.6
Restricted cash	57.1	91.6
Accounts and notes receivable (net of allowance of $14.8 in 2007 and $15.9 in 2006)	1,271.8	1,212.9
Inventories	266.1	241.4
Derivative assets	2,190.3	1,878.2
Margin deposits	99.6	59.3
Deferred income taxes	363.8	337.2
Other current assets and deferred charges	360.8	232.8
Total current assets	6,420.7	6,322.0
Restricted cash	34.5	34.5
Investments	868.7	866.0
Property, plant and equipment net	14,451.0	14,180.7
Derivative assets	2,606.0	2,384.9
Goodwill	1,011.4	1,011.4
Other assets and deferred charges	543.7	602.9
Total assets	$ 25,936.0	$ 25,402.4
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,164.1	$ 1,148.5
Accrued liabilities	1,135.7	1,241.4
Customer margin deposits payable	203.5	128.7
Derivative liabilities	2,141.5	1,782.9
Long-term debt due within one year	387.7	392.1
Total current liabilities	5,032.5	4,693.6
Long-term debt	7,507.5	7,622.0
Deferred income taxes	2,961.4	2,879.9
Derivative liabilities	2,266.4	2,043.8
Other liabilities and deferred income	899.1	1,009.1
Contingent liabilities and commitments (Note 8)		
Minority interests in consolidated subsidiaries	1,077.4	1,080.8
Stockholders equity:		

Common stock (960 million shares authorized at $1 par value; 604.2 million issued at March 31, 2007 and 602.8 million shares issued at December 31, 2006)	604.2	602.8
Capital in excess of par value	6,641.8	6,605.7
Accumulated deficit	(970.9)	(1,034.0)
Accumulated other comprehensive loss	(42.2)	(60.1)
	6,232.9	6,114.4
Less treasury stock, at cost (5.7 million shares of common stock in 2007 and 2006)	(41.2)	(41.2)
Total stockholders equity	6,191.7	6,073.2
Total liabilities and stockholders equity	$ 25,936.0	$ 25,402.4

See accompanying notes.

4

Table of Contents

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

(Dollars in millions)	Three months ended March 31, 2007	2006
OPERATING ACTIVITIES:		
Net income	$ 134.0	$ 131.9
Adjustments to reconcile to net cash provided by operations:		
Income from discontinued operations	(2.2)	(.8)
Depreciation, depletion and amortization	248.2	197.0
Provision for deferred income taxes	72.4	74.6
Provision for loss on investments, property and other assets	3.6	2.4
Net gain on disposition of assets	(.7)	(10.3)
Early debt retirement costs		27.0
Minority interest in income of consolidated subsidiaries	14.0	7.1
Amortization of stock-based awards	16.8	10.5
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(63.2)	440.5
Inventories	(24.8)	(5.2)
Margin deposits and customer margin deposits payable	34.5	(150.1)
Other current assets and deferred charges	3.2	(46.1)
Accounts payable	8.9	(313.1)
Accrued liabilities	(189.4)	(212.4)
Changes in current and noncurrent derivative assets and liabilities	67.8	21.7
Other, including changes in noncurrent assets and liabilities	(23.3)	(10.0)
Net cash provided by operating activities	299.8	164.7
FINANCING ACTIVITIES:		
Payments of long-term debt	(118.6)	(64.1)
Proceeds from issuance of common stock	14.5	10.2
Premiums paid on early debt retirement costs		(25.8)
Tax benefit of stock-based awards	7.6	
Dividends paid	(54.1)	(44.6)
Dividends and distributions paid to minority interests	(20.3)	(6.6)
Changes in restricted cash	34.7	7.3
Changes in cash overdrafts	17.0	(31.0)
Other net	3.1	(1.2)
Net cash used by financing activities	(116.1)	(155.8)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(509.1)	(468.3)
Net proceeds from dispositions	.2	12.5

Changes in accounts payable and accrued liabilities	(5.7)	14.5
Purchases of investments/advances to affiliates	(21.2)	(9.7)
Purchases of auction rate securities	(173.2)	(95.3)
Proceeds from sales of auction rate securities	44.6	19.4
Proceeds from dispositions of investments and other assets	17.8	31.4
Other net	5.5	4.4
Net cash used by investing activities	(641.1)	(491.1)
Decrease in cash and cash equivalents	(457.4)	(482.2)
Cash and cash equivalents at beginning of period	2,268.6	1,597.2
Cash and cash equivalents at end of period	$ 1,811.2	$ 1,115.0

See accompanying notes.

Table of Contents

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

Note 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, 2007, and results of operations and cash flows for the three months ended March 31, 2007 and 2006.

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.

Note 2. Basis of Presentation

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

We currently own approximately 22.5 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us. Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.

Note 3. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended March 31,	
	2007	2006
	(Millions)	
Current:		
Federal	$ 2.8	$ 3.1
State	(2.4)	2.6
Foreign	9.3	8.0
	9.7	13.7
Deferred:		
Federal	56.6	56.4
State	9.8	12.6
Foreign	6.0	5.6
	72.4	74.6
Total provision	$ 82.1	$ 88.3

The effective tax rate for the three months ended March 31, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and net foreign operations.

The effective tax rate for the three months ended March 31, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes.

Table of Contents

Notes (Continued)

Effective January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109 (FIN 48). The Interpretation prescribes guidance for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. To recognize a tax position, the enterprise determines whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. A tax position that meets the more likely than not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured as the largest amount of benefit, determined on a cumulative probability basis, that is greater than 50 percent likely of being realized upon ultimate settlement.

FIN 48 is effective for fiscal years beginning after December 15, 2006. The cumulative effect of applying the Interpretation must be reported as an adjustment to the opening balance of retained earnings in the year of adoption. We adopted FIN 48 beginning January 1, 2007, as required. The net impact of the cumulative effect of adopting FIN 48 was approximately a $16.8 million decrease in retained earnings.

As of January 1, 2007, we had approximately $93 million of unrecognized tax benefits. If recognized, approximately $83 million, net of federal tax expense, would be recorded as a reduction of income tax expense. There have been no significant changes to these amounts during the quarter ended March 31, 2007.

We recognize related interest and penalties as a component of income tax expense. Approximately $97 million of interest and $5 million of penalties have been accrued at January 1, 2007. Of the $97 million interest accrued, approximately $22 million relates to uncertain tax positions.

As of January 1, 2007, the Internal Revenue Service (IRS) examination of Williams consolidated U.S. income tax return for 2002 was in process. During the first quarter of 2007, the IRS also commenced examination of the 2003 through 2005 consolidated U.S. income tax returns. IRS examinations for 1996 through 2001 have been completed but the years remain open while certain issues are under review with the Appeals Division of the IRS. The statute of limitations for most states expire one year after IRS audit settlement.

Generally, tax returns for our Venezuelan and Canadian entities are open to audit from 2002 through 2006. Certain Canadian entities are currently under examination.

Table of Contents

Notes (Continued)

Note 4. Earnings Per Common Share from Continuing Operations

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

	Three months ended March 31, 2007	2006
	(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 (1)	$ 131.8	$ 131.1
Basic weighted-average shares	598,031	591,407
Effect of dilutive securities:		
Unvested restricted stock units (2)	1,363	834
Stock options	4,751	4,355
Convertible debentures (3)	7,325	10,477
Diluted weighted-average shares	611,470	607,073
Earnings per common share from continuing operations:		
Basic	$ .22	$ .22
Diluted	$ .22	$ .22

(1) The three months ended March 31, 2007 and 2006 include approximately $.7 million and $1 million, respectively, of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) The unvested restricted stock units outstanding at March 31, 2007, will vest over the period from May 2007 to March 2010.

(3) During January 2006, we converted approximately $220.2 million of our 5.5 percent junior subordinated convertible debentures in exchange for 20.2 million shares of common stock, a $25.8 million cash premium, and $1.5 million of accrued interest. At March 31, 2007, approximately $80 million of our convertible debentures remain outstanding.

The table below includes information related to stock 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.

	March 31, 2007	March 31, 2006
Options excluded (millions)	4.4	4.6
Weighted-average exercise prices of options excluded	$ 34.19	$ 35.35
Exercise price ranges of options excluded	$27.15 $42.29	$22.68 $42.29
First quarter weighted-average market price	$ 27.04	$ 22.40

In the first quarter of 2006, an additional 3.2 million options with exercise prices less than the first quarter weighted-average market price were excluded from the computation of weighted-average stock options due to the shares being antidilutive.

Table of Contents

Notes (Continued)

Note 5. Employee Benefit Plans

Net periodic pension expense and *other postretirement benefit expense* for the three months ended March 31, 2007 and 2006 are as follows:

	Pension Benefits Three months ended March 31,		Other Postretirement Benefits Three months ended March 31,	
	2007	2006	2007	2006
	(Millions)			
Components of net periodic pension and other postretirement benefit expense:				
Service cost	$ 5.8	$ 5.7	$ .8	$ .9
Interest cost	13.1	11.8	4.4	5.2
Expected return on plan assets	(17.9)	(16.9)	(3.0)	(2.9)
Amortization of prior service credit	(.1)	(.1)	(.1)	(.1)
Amortization of net actuarial loss	4.1	3.8		.9
Regulatory asset amortization (deferral)		(.1)	1.3	1.6
Net periodic pension and other postretirement benefit expense	$ 5.0	$ 4.2	$ 3.4	$ 5.6

During the first quarter of 2007, we have contributed $10.2 million to our pension plans and $3.5 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $31 million to our pension plans in 2007 for a total of approximately $41 million. We presently anticipate making additional contributions of approximately $12 million to our other postretirement benefit plans in 2007 for a total of approximately $16 million.

Note 6. Inventories

Inventories at March 31, 2007 and December 31, 2006 are as follows:

	March 31, 2007	December 31, 2006
	(Millions)	
Natural gas liquids	$ 112.2	$ 77.9
Materials, supplies and other	94.7	85.9
Natural gas in underground storage	59.2	77.6
	$ 266.1	$ 241.4

Note 7. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At March 31, 2007, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at

	March 31, 2007 (Millions)
$500 million unsecured credit facilities	$ 351.0
$700 million unsecured credit facilities	$ 479.7
$1.5 billion unsecured credit facility	$ 28.0

Exploration & Production s credit agreement

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement

Notes (Continued)
including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Issuances and retirements

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior unsecured notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement.

Registration payment arrangements

Under the terms of the Northwest Pipeline $185 million 5.95 percent senior unsecured notes mentioned above, Northwest Pipeline is obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes issued under the Securities Act of 1933, as amended, within 180 days from closing and use its commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing. Northwest Pipeline may be required to provide a shelf registration statement to cover resales of the notes under certain circumstances. Northwest Pipeline may also be required to pay additional interest, up to a maximum of 0.5 percent annually, if it fails to satisfy these obligations.

On June 20, 2006, Williams Partners L.P. issued $150 million aggregate principal amount of 7.5 percent senior unsecured notes in a private debt placement. On December 13, 2006, Williams Partners L.P. issued $600 million aggregate principal amount of 7.25 percent senior unsecured notes in a private debt placement. In connection with these issuances, Williams Partners L.P. entered into registration rights agreements with the initial purchasers of the senior unsecured notes. In these agreements they agreed to conduct a registered exchange offer for the senior unsecured notes or cause to become effective a shelf registration statement providing for resale of the senior unsecured notes. If Williams Partners L.P. fails to initiate the exchange offers by May 30, 2007, they will be required to pay additional interest, up to a maximum of 0.5 percent annually. Williams Partners L.P. initiated exchange offers for both series on April 10, 2007.

On December 13, 2006, Williams Partners L.P. issued approximately $350 million of common and Class B units in a private equity offering. In connection with these issuances, Williams Partners L.P. entered into a registration rights agreement with the initial purchasers whereby Williams Partners L.P. agreed to file a shelf registration statement providing for the resale of the units. Additionally, the registration rights agreement provides for the registration of common units that would be issued upon conversion of the Class B units. If the shelf is unavailable for a period that exceeds an aggregate of 30 days in any 90-day period or 105 days in any 365-day period, the purchasers are entitled to receive liquidated damages. Liquidated damages are calculated as 0.25% of the Liquidated Damages Multiplier per 30-day period for the first 60 days following the 90th day, increasing by an additional 0.25% of the Liquidated Damages Multiplier per 30-day period for each subsequent 60 days, up to a maximum of 1.00% of the Liquidated Damages Multiplier per 30-day period. The Liquidated Damages Multiplier is (i) the product of $36.59 times the number of common units purchased that have not yet been resold pursuant to the registration statement plus (ii) the product of $35.81 times the number of Class B Units purchased.

As of March 31, 2007, we have not accrued any liabilities for these registration payment arrangements.

Note 8. Contingent Liabilities and Commitments

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of March 31, 2007, which we believe is adequate for any refunds that may be required.

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 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including

Notes (Continued)
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 substantially resolved each of these issues with these parties.

As a result of a December 19, 2006, Ninth Circuit Court of Appeals decision, certain contracts that Power entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which Power sold electricity, totaled approximately $89 million in revenue. While Power is not a party to the cases involved in the appellate court decision, the buyer of electricity from Power is a party to the cases and claims that Power must refund to the buyer any loss it suffers due to the decision and the FERC s reconsideration of the contract terms at issue in the decision.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as various California end users that did not participate in 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 nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $21 million at March 31, 2007. Collection of the interest is subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceedings, including the refund period, were made to the Ninth Circuit Court of Appeals. On August 2, 2006, the Ninth Circuit issued its order that largely upheld the FERC s prior rulings, but it expanded the types of transactions that were made subject to refund. Because of our settlement, we do not expect this decision will have a material impact on us. No final refund calculation, however, has been made, and certain aspects of the refund calculation process remain unclear and prevent that final refund calculation. As part of the State Settlement, an additional $45 million, previously accrued, remains to be paid to the California Attorney General (or his designee) over the next three years, with final payment of $15 million due on January 1, 2010.

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. In 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. Three former traders with Power have pled guilty to manipulation of gas prices through misreporting to an industry trade periodical. One former trader has pled not guilty. On February 21, 2006, we entered into a deferred prosecution agreement with the Department of Justice (DOJ) that is intended to resolve this matter. The agreement obligated us to pay a total of $50 million, of which $20 million was paid in March 2006. The remaining $30 million was paid in February 2007. Absent a breach, the agreement will expire 15 months from the date of execution of the agreement and no further action will be taken by the DOJ.

Civil suits based on allegations of manipulating the gas indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

- Class action litigation in federal court in Nevada alleging that we manipulated gas prices for direct purchasers of gas in California. We have settled this matter for $2.4 million and are awaiting the court s approval.

- State court in California on behalf of certain individual gas users.

Table of Contents

Notes (Continued)

Class action litigation in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. The Tennessee purchasers have appealed the court s February 2007 dismissal of the case before it. The cases in the other jurisdictions have been removed to federal court.

It is reasonably possible that additional amounts may be necessary to resolve the remaining outstanding litigation in this area, the amount of which cannot be reasonably estimated at this time.

Mobile Bay Expansion

In December 2002, an administrative law judge at the FERC issued an initial decision in Transcontinental Gas Pipe Line Corporation s (Transco) 2001 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. In March 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge s decision 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 $117 million, including interest, through March 31, 2007, in addition to increased costs going forward. Certain parties have filed appeals in federal court seeking to have the FERC s ruling on the rolled-in rates overturned.

Enron Bankruptcy

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively Enron) related to its bankruptcy filed in December 2001. In 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. In 2003, Enron filed objections to these claims. We have resolved Enron s objections, subject to court approval. Pursuant to the sales agreement, the purchaser of the claims demanded repayment of the purchase price for the reduced portions of the claims. In February 2007, we completed a settlement with the purchaser covering any potential repayment obligations.

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, 2007, we had accrued liabilities of $6 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above.

Beginning in the mid-1980 s, our Northwest Pipeline subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and

Table of Contents

Notes (Continued)

Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Currently, Northwest Pipeline is assessing the actions needed for the sites to comply with Washington s current environmental standards. At March 31, 2007, we have accrued liabilities totaling approximately $5 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At March 31, 2007, we have accrued liabilities totaling approximately $7 million for these costs.

In August 2005, our subsidiary, Williams Production RMT Company, voluntarily disclosed to the Colorado Department of Public Health and Environment (CDPHE) two air permit violations. We have reached an agreement-in-principle with the CDPHE in which we agreed to pay a $180,000 penalty and to conduct a supplemental environmental project to upgrade our equipment. We expect that a definitive agreement will be finalized soon.

In March 2006, the CDPHE issued a notice of violation (NOV) to Williams Production RMT Company related to our operating permit for the Rulison oil separation and evaporation facility. On April 12, 2006, we met with the CDPHE to discuss the allegations contained in the NOV. In May 2006, we provided additional information to the agency regarding the emission estimates for operations from 1997 through 2003 and applied for updated permits.

In July 2006, the CDPHE issued an NOV to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn Gas Plants in Garfield County, Colorado. In September 2006, we met with the CDPHE to discuss the allegations contained in the NOV, and in October 2006, we provided additional requested information to the agency.

In August 2006, the CDPHE issued a NOV to Williams Production RMT Company related to our Grand Valley Oil Separation and Evaporation Facility located in Garfield County, Colorado in which the CDPHE alleged that we failed to obtain a construction permit and to comply with certain provisions of our existing permit. In September 2006, we met with the CDPHE, and in October 2006, we provided additional requested information to the agency.

On April 11, 2007, the New Mexico Environment Department s Air Quality Bureau (NMED) issued a NOV to Williams Four Corners, LLC that alleges various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. We are investigating the matter.

On April 16, 2007, the CDPHE issued a NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. We are investigating the matter.

On April 27, 2007, the Wyoming Department of Environmental Quality issued a NOV to Williams Production RMT Company that alleges recurring violations of various Wyoming Pollution Discharge Elimination System permits in connection with our coal bed methane gas production facilities in the state. We have begun our investigation of the matter.

In July 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. In March 2004, the DOJ invited the new owner of Williams Energy Partners and Magellan Midstream Partners, L.P. (Magellan) to enter into negotiations regarding alleged violations of the Clean Water Act. With the exception of four minor release events that underwent earlier cleanup operation under state enforcement actions, our environmental indemnification obligations to Magellan were released in a 2004 buyout. We do not expect further enforcement action with respect to the four release events or two 2006 spills at our Colorado and Wyoming facilities after providing additional requested information to the DOJ.

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.

Notes (Continued)

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, 2007, we have accrued liabilities of approximately $9 million for such excess costs.

Other

At March 31, 2007, we have accrued environmental liabilities totaling approximately $24 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;
- Former exploration and production and mining operations.

These costs include certain conditions at specified locations related primarily to soil and groundwater contamination and any penalty assessed on Williams Refining & Marketing, L.L.C. (Williams Refining) associated with noncompliance with the EPA s National Emission Standards for Hazardous Air Pollutants (NESHAP). In 2002, Williams Refining submitted a self-disclosure letter to the EPA 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. In 2004, Williams Refining and the new owner of the Memphis refinery met with the EPA and the DOJ to discuss alleged violations and proposed penalties due to noncompliance issues identified in the report, including the benzene NESHAP issue. In July and August 2006, we finalized our agreements that resolved both the government s claims against us for alleged violations and an indemnity dispute with the purchaser in connection with our 2003 sale of the Memphis refinery. We have paid the required settlement amounts to the purchaser, and our payment to the government awaits the court s approval of the settlement.

In 2004, our Gulf Liquids subsidiary initiated a self-audit of all environmental conditions (air, water, waste) at three facilities: Geismar, Sorrento, and Chalmette, Louisiana. The audit revealed numerous infractions of Louisiana environmental regulations and resulted in a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ). No specific penalty amount was assessed. Instead, LDEQ was required by Louisiana law to demand a profit and loss statement to determine the financial benefit obtained by noncompliance and to assess a penalty accordingly. Gulf Liquids offered $91,500 as a single, final, global multi-media settlement. Subsequent negotiations have resulted in a revised offer of $109,000, which LDEQ is currently reviewing.

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, but the amount cannot be reasonably estimated at this time.

Notes (Continued)

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants 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 and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants have opposed class certification and a hearing on plaintiffs second motion to certify the class was held in April 2005. We are awaiting a decision from the court.

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 sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, 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 had 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. In 1999, the DOJ announced that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg s measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg s royalty valuation claims. In May 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

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 we 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 we 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. In 2004, Grynberg 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 was originally set for May 2006, but the parties have negotiated an agreement dismissing the measurement claims and deferring further proceedings on the royalty claims until resolution of an appeal in another case.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended

Notes (Continued)
complaints of the WilTel securities holders and of our securities holders added numerous claims related to Power. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

Litigation with the WilTel equity holders continues but the trial has been stayed pending decisions on various motions for summary judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement or as a result of trial will not likely be covered by insurance, as our insurance coverage has been fully utilized by the settlement described above. The extent of the obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure materially exceeds amounts accrued for this matter.

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. In the third quarter of 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions. 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. In 2004, we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable.

The FERC and the RCA completed their reviews of the initial decisions and in 2005 issued substantially similar orders generally affirming the initial decisions. In June 2006, the FERC, after two sets of rehearing requests, entered its final order (FERC Final Order). During this administrative rehearing process all other appeals of the initial decisions were stayed including ExxonMobil s appeal to the D.C. Circuit Court of Appeals asserting that the FERC s reliance on the Highway Reauthorization Act as the basis for limiting the retroactive effect violates, among other things, the separation of powers under the U.S. Constitution by interfering with the FERC s independent decision-making role. ExxonMobil filed a similar appeal in the Alaska Superior Court. We also appealed the FERC s order to the extent of its ruling on the West Coast Heavy Distillate component.

The Quality Bank Administrator issued his interpretations of the payment obligations under the FERC Final Order, and we and others filed exceptions to these instructions with the FERC. We expect the FERC s ruling on these payment instruction exceptions by the end of 2007. Once the FERC rules, the Administrator will invoice us for amounts due, and we will be required to pay the invoiced amounts, subject to the outcome of the appeals of the FERC Final Order. We estimate that our net obligation could be as much as $116 million. Amounts accrued in excess of this estimated obligation will be retained pending resolution of all appeals.

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. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found Power jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both we and AES Redondo Beach filed notices of appeal that were heard at the city level. On December 13, 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming our utility user tax liability and reversing AES Redondo Beach s liability because the officer ruled that AES Redondo Beach is an exempt public utility. We appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES

Redondo Beach. On April 11, 2007, the court ruled that we must pay the city

16

Table of Contents

Notes (Continued)

the disputed amount of approximately $57 million by May 1, 2007, in order to pursue our appeal. On April 30, 2007, we paid the city the disputed amount. Despite the city hearing officer s unfavorable decision and the payment to preserve our appeal rights, we do not believe a contingent loss is probable.

The city s assessment of our liability for the periods from 1998 through September 2006 is approximately $69 million (inclusive of interest and penalties). We have protested all these assessments and requested hearings on them. We and AES Redondo Beach have also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals. We believe that under our tolling agreement related to the Redondo Beach generating facility, AES Redondo Beach is responsible for taxes of the nature asserted by the city; however, AES Redondo Beach has notified us that it does not agree.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. Gulsby and Gulsby-Bay defaulted on the construction contracts. In the fall of 2001, the contractors, sureties, and Gulf Liquids filed multiple cases in Louisiana and Texas. In January 2002, NAICO added Gulf Liquids co-venturer Power to the suits as a third-party defendant. Gulf Liquids asserted claims against the contractors and sureties for, among other things, breach of contract requesting contractual and consequential damages from $40 million to $80 million, any of which is subject to a sharing arrangement with XL Insurance Company.

At the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual damages verdict against Power and Gulf Liquids on July 31, 2006 and its related punitive damages verdict on August 1, 2006. The court is not expected to enter any judgment until the second or third quarter of 2007. Based on our interpretation of the jury verdicts, we have estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $23 million, all of which have been accrued as of March 31, 2007. In addition, it is reasonably possible that any ultimate judgment may include additional amounts of approximately $199 million in excess of our accrual, which primarily represents our estimate of potential punitive damage exposure under Texas law.

Wyoming severance taxes

The Wyoming Department of Audit (DOA) audited the severance tax reporting for our subsidiary Williams Production RMT Company for the production years 2000 through 2002. In August 2006, the DOA assessed additional severance tax and interest for those periods of approximately $3 million. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes, which is estimated to result in additional taxes of approximately $2 million, including interest. We dispute the DOA s interpretation of the statutory obligation and have appealed this assessment to the Wyoming State Board of Equalization. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $21 million to $23 million in taxes and interest from January 1, 2003, through March 31, 2007.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. The parties have agreed to stay this action in order to participate in ongoing mediation.

Notes (Continued)

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.

We sold a natural gas liquids pipeline system in 2002, and in July 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks approximately $18.5 million in damages and our specific performance under certain guarantees. In 2006, we filed our answer to the purchaser s complaint denying all liability. We anticipate that the trial will occur in the first quarter of 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At March 31, 2007, 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, 2007, Power s estimated committed payments under these contracts range from approximately $318 million to $425 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 sixteen years are approximately $5.4 billion.

Guarantees

In connection with agreements executed prior to our acquisition of Transco 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 that 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 certain demands 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. However, management believes that the probability of material payments is remote.

Notes (Continued)

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.

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. These indemnifications 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 $20 million on behalf of a certain entity in which we have an equity ownership interest. These expire by January 2008 and have no carrying value.

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, 2007.

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. The maximum potential exposure is approximately $45 million at March 31, 2007. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $41 million at March 31, 2007.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third-party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

Table of Contents

Notes (Continued)

Note 9. Comprehensive Income

Comprehensive income is as follows:

	Three months ended March 31,	
	2007	2006
	(Millions)	
Net income	$ 134.0	$ 131.9
Other comprehensive income:		
Net unrealized gains on derivative instruments	10.0	189.0
Net reclassification into earnings of derivative instrument losses	9.9	101.4
Foreign currency translation adjustments	3.1	(2.2)
Minimum pension liability adjustment		(.3)
Pension benefits:		
Amortization of prior service credit	(.1)	
Amortization of net actuarial loss	4.0	
Other postretirement benefits:		
Amortization of prior service cost	.3	
Other comprehensive income before taxes	27.2	287.9
Income tax provision on other comprehensive income	(9.3)	(111.1)
Other comprehensive income	17.9	176.8
Comprehensive income	$ 151.9	$ 308.7

Net unrealized gains on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The net unrealized gains at March 31, 2007, include net unrealized gains on forward natural gas purchases and sales of approximately $33 million, partially offset by net unrealized losses on forward power purchases and sales of approximately $23 million. The net unrealized gains at March 31, 2006, include net unrealized gains on forward natural gas purchases and sales of approximately $97 million and net unrealized gains on forward power purchases and sales of approximately $92 million.

Note 10. Segment Disclosures

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. Our master limited partnership, Williams Partners L.P., is consolidated within our Midstream segment. (See Note 2.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *depreciation, depletion and amortization*, *equity earnings (losses)* and *income (loss) from investments* including 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.

The majority of energy commodity hedging by certain of our business units has historically been done through intercompany derivatives with our Power segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties. However, in the first quarter of 2007, Exploration & Production entered into certain hedges directly with third parties under its new credit agreement. (See Note 7.)

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

Table of Contents

Notes (Continued)

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income* as reported in the Consolidated Statement of Income.

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Power (Millions)	Other	Eliminations	Total
Three months ended March 31, 2007							
Segment revenues:							
External	$ (62.4)	$ 363.0	$ 984.1	$ 1,564.6	$ 2.8	$	$ 2,852.1
Internal	545.1	7.8	11.3	210.5	4.0	(778.7)	
Total revenues	$ 482.7	$ 370.8	$ 995.4	$ 1,775.1	$ 6.8	$ (778.7)	$ 2,852.1
Segment profit (loss)	$ 188.1	$ 149.7	$ 154.0	$ (81.1)	$ .7	$	$ 411.4
Less:							
Equity earnings	5.3	9.3	6.7		.1		21.4
Segment operating income (loss)	$ 182.8	$ 140.4	$ 147.3	$ (81.1)	$ .6	$	390.0
General corporate expenses							(39.4)
Consolidated operating income							$ 350.6
Three months ended March 31, 2006							
Segment revenues:							
External	$ (59.5)	$ 330.5	$ 966.1	$ 1,787.6	$ 2.8	$	$ 3,027.5
Internal	415.5	3.5	13.3	265.6	4.1	(702.0)	
Total revenues	$ 356.0	$ 334.0	$ 979.4	$ 2,053.2	$ 6.9	$ (702.0)	$ 3,027.5
Segment profit (loss)	$ 147.6	$ 134.7	$ 151.5	$ (22.5)	$ 1.0	$	$ 412.3
Less:							
Equity earnings (losses)	5.0	7.5	9.9	(.2)			22.2
Segment operating income (loss)	$ 142.6	$ 127.2	$ 141.6	$ (22.3)	$ 1.0	$	390.1
General corporate expenses							(31.8)
							$ 358.3

Consolidated operating income

The following table reflects *total assets* by reporting segment.

	Total Assets	
	March 31, 2007	**December 31, 2006**
	(Millions)	
Exploration & Production	$ 8,442.5	$ 7,850.9
Gas Pipeline	8,368.5	8,331.7
Midstream Gas & Liquids	5,636.9	5,483.8
Power (1)	8,087.6	6,884.8
Other	3,933.5	4,224.6
Eliminations (2)	(8,533.0)	(7,373.4)
Total assets	$ 25,936.0	$ 25,402.4

(1) The increase in Power s total assets is due primarily to an increase in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Power s derivative assets are substantially offset by their derivative liabilities.

(2) The increase in Eliminations is due primarily to an increase in the intercompany derivative balances.

Note 11. Recent Accounting Standards

In September 2006, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements (SFAS No. 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and is generally applied prospectively. We will assess the impact of SFAS No. 157 on our Consolidated Financial Statements.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 establishes a fair value option permitting entities to elect the option to measure eligible financial instruments and certain other items

Notes (Continued)

at fair value on specified election dates. Unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. The fair value option may be applied on an instrument-by-instrument basis, with a few exceptions, is irrevocable and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007 and should not be applied retrospectively to fiscal years beginning prior to the effective date. On the adoption date, an entity may elect the fair value option for eligible items existing at that date and the adjustment for the initial remeasurement of those items to fair value should be reported as a cumulative effect adjustment to the opening balance of retained earnings. We continue to assess whether to apply the provisions of SFAS No. 159 to eligible financial instruments in place on the adoption date and the related impact on our Consolidated Financial Statements.

On March 29, 2007, the FERC issued Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans. The guidance is being provided to all jurisdictional entities to ensure proper and consistent implementation of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R) for FERC financial reporting purposes beginning with the 2007 FERC Form 2 to be filed in 2008. We are currently evaluating the impact of the FERC guidance on our Gas Pipeline segment and Consolidated Financial Statements.

In April 2007, the FASB issued a Staff Position (FSP) on a previously issued FIN, FSP FIN 39-1, Amendment of FASB Interpretation No. 39. FSP FIN 39-1 amends FIN 39, Offsetting of Amounts Related to Certain Contracts (as amended) by addressing offsetting fair value amounts recognized for the right to reclaim or obligation to return cash collateral arising from derivative instruments that have been offset pursuant to a master netting arrangement. The FSP requires disclosure of the accounting policy related to offsetting fair value amounts as well as disclosure of amounts recognized for the right to reclaim or obligation to return cash collateral. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted, and is applied retrospectively as a change in accounting principle for all financial statements presented. We will assess the impact of FSP FIN 39-1 on our Consolidated Financial Statements.

Table of Contents

ITEM 2
Management s Discussion and Analysis of Financial Condition and Results of Operations

Company Outlook

Our plan for 2007 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit.
- Invest in our natural gas businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position.
- Continue to increase natural gas production and reserves.
- Increase the scale of our gathering and processing business in key growth basins.
- Successfully resolving the rate cases for both Northwest Pipeline and Transco.
- Execute power contracts that offset a significant percentage of our financial obligations associated with our tolling agreements.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 8 of Notes to Consolidated Financial Statements);
- General economic and industry downturn.

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining our desired level of at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities.

Our *income from continuing operations* for the three months ended March 31, 2007, was relatively comparable to the three months ended March 31, 2006. This result is reflective of:

- Increased operating income at Exploration & Production associated with increased production and higher average net realized prices;
- Increased operating income at Gas Pipeline due to new rates that went into effect during the first quarter of 2007;
- The absence of early debt retirement costs incurred during the first quarter of 2006;
- Offsetting these improvements is decreased operating income at Power primarily due to increased unrealized mark-to-market losses.

See additional discussion in Results of Operations.

Management s Discussion and Analysis (Continued)

Our *net cash provided by operating activities* increased $135.1 million primarily due to a decrease in net cash outflows from *margin deposits and customer margin deposits payable.* See additional discussion in Management s Discussion and Analysis of Financial Condition.

Recent Events

In April 2007, our Board of Directors approved a regular quarterly dividend of 10 cents per share, which reflects an increase of 11 percent compared to the 9 cents per share that we paid in each of the four prior quarters and marks the fourth increase in our dividend since late 2004.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline s system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

In the first quarter of 2007, Power executed agreements to sell dispatch and tolling rights and supply natural gas in southern California for periods through 2011. These contracts mirror Power s rights under its California tolling agreement and represent up to 1,920 megawatts of power.

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition 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 2006 Annual Report on Form 10-K.

Table of Contents

Management s Discussion and 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, 2007, compared to the three months ended March 31, 2006. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31, 2007	2006	$ Change from 2006 *	% Change from 2006 *
	(Millions)			
Revenues	$ 2,852.1	$ 3,027.5	-175.4	-6%
Costs and expenses:				
Costs and operating expenses	2,362.7	2,588.7	+226.0	+9%
Selling, general and administrative expenses	117.5	71.0	-46.5	-65%
Other income net	(18.1)	(22.3)	-4.2	-19%
General corporate expenses	39.4	31.8	-7.6	-24%
Total costs and expenses	2,501.5	2,669.2		
Operating income	350.6	358.3		
Interest accrued net	(168.4)	(159.8)	-8.6	-5%
Investing income	43.7	46.9	-3.2	-7%
Early debt retirement costs		(27.0)	+27.0	+100%
Minority interest in income of consolidated subsidiaries	(14.0)	(7.1)	-6.9	-97%
Other income net	2.0	8.1	-6.1	-75%
Income from continuing operations before income taxes	213.9	219.4		
Provision for income taxes	82.1	88.3	+6.2	+7%
Income from continuing operations	131.8	131.1		
Income from discontinued operations	2.2	.8	+1.4	+175%
Net income	$ 134.0	$ 131.9		

* + = Favorable change to *net income*; = Unfavorable change to *net income*.

Three months ended March 31, 2007 vs. three months ended March 31, 2006

The decrease in *revenues* is primarily due to a decrease in realized revenues associated with reduced power sales volumes and reduced natural gas sales prices at Power. Additionally, the effect of a change in forward prices on natural gas contracts not designated as cash flow hedges and decreased gains from hedge ineffectiveness had an unfavorable impact on revenues. Partially offsetting these decreases are increased production revenues at Exploration

& Production due to both increased volumes and net average realized prices. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

The decrease in *costs and operating expenses* is largely due to decreased power purchase volumes and reduced natural gas purchase prices at Power. Partially offsetting these decreases are increased depreciation, depletion and amortization and lease operating expense at Exploration & Production.

The increase in *selling, general and administrative (SG&A) expenses* is primarily due to the absence of a 2006 gain on sale of certain receivables at Power of $23.7 million and higher costs due to increased staffing in support of drilling and operational activity at Exploration & Production.

Other income net within *operating income* in 2007 includes:

Income of approximately $8 million due to the reversal of a planned major maintenance accrual (see further discussion in Midstream s Results of Operations);

Net gains of approximately $6 million on foreign currency exchanges, primarily at Midstream.

Table of Contents

Management s Discussion and Analysis (Continued)

Other income net within *operating income* in 2006 includes:

Income of $9 million due to a settlement of an international contract dispute at Midstream;

An approximate $4 million gain on sale of idle gas treating equipment at Midstream;

An approximate $4 million favorable transportation settlement at Midstream.

The increase in *general corporate expenses* is attributable to various factors, including higher information technology, consulting and insurance costs.

Interest accrued net increased primarily due to changes in our debt portfolio, most significantly the issuance of new debt in 2006 by Williams Partners L.P., our consolidated master limited partnership.

Investing income decreased primarily due to an approximate $9 million adjustment to accrued interest receivable associated with certain California litigation and the absence of an approximate $7 million gain on sale of an international investment in 2006. Partially offsetting these items is increased interest income associated with larger cash and cash equivalent balances combined with higher rates of return.

Early debt retirement costs in first quarter 2006 includes $25.8 million in premiums and $1.2 million in fees related to the January 2006 debt conversion. (See Note 4 of Notes to Consolidated Financial Statements.)

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P.

Provision for income taxes was favorable primarily due to a reduction in the amount of state income taxes accrued. The effective tax rate for the three months ended March 31, 2007, is greater than the federal statutory rate due primarily to the effect of state income taxes and net foreign operations. The effective tax rate for the three months ended March 31, 2006, is greater than the federal statutory rate due primarily to the effect of state income taxes.

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Three Months Ended March 31, 2007

During the first three months of 2007, we continued our strategy of a rapid execution of our development drilling program in our growth basins. Accordingly, we:

- Increased average daily domestic production levels by approximately 28 percent compared to the first three months of 2006. The average daily domestic production for the first three months was approximately 845 million cubic feet of gas equivalent (MMcfe) in 2007 compared to 661 MMcfe in 2006. The increased production is primarily due to increased development within the Piceance and Powder River basins.

- Increased capital expenditures for domestic drilling, development, and acquisition activity in the first three months of 2007 by approximately $30 million compared to 2006.

The benefits of higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to higher well service and industry costs and increased production volumes.

Significant events

In February 2007, we entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Margin requirements, if any, under this new facility are dependent on the level of hedging and on natural gas reserves value. (See Note 7 of Notes to Consolidated Financial Statements.)

We may also execute hedges with the Power segment which, in turn, executes offsetting derivative contracts with unrelated third parties. In this situation, Power, generally, bears the counterparty performance risks associated with unrelated third parties. Hedging decisions primarily are made considering our overall commodity risk exposure and are not executed independently by Exploration & Production.

During the first three months of 2007, we entered into various derivative collar agreements at the basin level which, in the aggregate, hedge an additional 80 MMcfe per day for production in 2008 and 90 MMcfe per day for production in 2009.

Outlook for the Remainder of 2007

Our expectations for the remainder of the year include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth through our remaining planned capital expenditures projected between $1 and $1.1 billion.

- Continuing to grow our average daily domestic production level with a goal of 10 to 20 percent growth compared to 2006.

Approximately 172 MMcfe per day of our forecasted 2007 daily production is hedged by NYMEX and basis fixed-price contracts at prices that average $3.89 per Mcfe at a basin level. In addition, we have collar agreements for each month remaining in 2007 as follows:

- NYMEX collar agreement for approximately 15 MMcfe per day at a weighted-average floor price of $6.50 per Mcfe and a weighted-average ceiling price of $8.25 per Mcfe.

- Northwest Pipeline/Rockies collar agreement for approximately 50 MMcfe per day at a floor price of $5.65 per Mcfe and a ceiling price of $7.45 per Mcfe at a basin level.

Table of Contents

Management s Discussion and Analysis (Continued)

El Paso/San Juan collar agreements totaling approximately 130 MMcfe per day at a weighted average floor price of $5.98 per Mcfe and a weighted average ceiling price of $9.63 per Mcfe at a basin level.

Mid-Continent (PEPL) collar agreements totaling approximately 77 MMcfe per day at a weighted average floor price of $6.82 per Mcfe and a weighted average ceiling price of $10.75 per Mcfe at a basin level.

Risks to achieving our expectations include weather conditions at certain of our locations, obtaining permits as planned for drilling, and market price movements.

Period-Over-Period Results

	Three months ended March 31,	
	2007	**2006**
	(Millions)	
Segment revenues	$ 482.7	$ 356.0
Segment profit	$ 188.1	$ 147.6

Three months ended March 31, 2007 vs. three months ended March 31, 2006

Total *segment revenues* increased $126.7 million, or 36 percent, primarily due to the following:

$126 million, or 44 percent, increase in domestic production revenues reflecting $80 million higher revenues associated with a 28 percent increase in production volumes sold and $46 million higher revenues associated with a 13 percent increase in net realized average prices. The increase in production volumes was from primarily the Piceance and Powder River basins. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

$26 million increase in revenues for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*.

The absence in 2007 of $9 million of unrealized gains from hedge ineffectiveness in the first quarter of 2006.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production. Approximately 20 percent of domestic production in the first quarter of 2007 was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.94 per Mcfe at a basin level compared to 44 percent hedged at a weighted-average price of $3.80 per Mcfe for the same period in 2006. Also in the first quarter of 2007, approximately 32 percent of domestic production was hedged in the collar agreements previously discussed in the Outlook section compared to 17 percent hedged in various collar agreements in the first quarter of 2006.

Total *segment costs and expenses* increased $87 million, primarily due to the following:

$41 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$26 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues;*

$14 million higher lease operating expense from the increased number of producing wells and higher well service and industry costs;

Table of Contents

Management s Discussion and Analysis (Continued)

- $14 million higher *SG&A expenses* primarily due to increased staffing in support of increased drilling and operational activity including higher compensation. In addition, we incurred higher legal, insurance, and information technology support costs also related to the increased activity. First quarter 2007 also includes approximately $5 million of expenses associated with a correction of costs incorrectly capitalized in prior periods.

First quarter 2006 *segment costs and expenses* do not include approximately $6 million in lease operating expenses related to that period. The amount was recorded in the second quarter of 2006.

The $40.5 million increase in *segment profit* is primarily due to the approximately 28 percent increase in production volumes sold and higher net realized average prices. Partially offsetting this increase are higher *segment costs and expenses* as previously discussed.

Gas Pipeline

Overview of Three Months Ended March 31, 2007

Status of rate cases

During 2006, Northwest Pipeline and Transco each filed general rate cases with the FERC for increases in rates due to higher costs in recent years. The new rates are effective, subject to refund, on January 1, 2007, for Northwest Pipeline and on March 1, 2007, for Transco. We expect the new rates to result in significantly higher revenues.

On March 30, 2007, the FERC approved the stipulation and settlement agreement with respect to the pending rate case for Northwest Pipeline. The settlement establishes an increase in general system firm transportation rates on Northwest Pipeline s system from $0.30760 to $0.40984 per Dth (dekatherm), effective January 1, 2007.

Outlook for the Remainder of 2007

Parachute Lateral project

In August 2006, we received FERC approval to construct a 37.6-mile expansion that will provide additional natural gas transportation capacity in northwest Colorado. The planned expansion will increase capacity by 450 Mdt/d through the 30-inch diameter line and is estimated to cost approximately $86 million. The expansion is expected to be in service in May 2007.

Leidy to Long Island expansion project

In May 2006, we received FERC approval to expand Transco s natural gas pipeline in the northeast United States. The estimated cost of the project is approximately $141 million. The expansion will provide 100 Mdt/d of incremental firm capacity and is expected to be in service by November 2007.

Potomac expansion project

In April 2007, we received FERC approval to expand Transco s existing facilities in the Mid-Atlantic region of the United States by constructing 16.4 miles of 42-inch pipeline. The project will provide 165 Mdt/d of incremental firm capacity. The estimated cost of the project is approximately $74 million, with an anticipated in-service date of November 2007.

Table of Contents

Management s Discussion and Analysis (Continued)

Period-Over-Period Results

	Three months ended March 31,	
	2007	**2006**
	(Millions)	
Segment revenues	$ 370.8	$ 334.0
Segment profit	$ 149.7	$ 134.7

Three months ended March 31, 2007 vs. three months ended March 31, 2006

Revenues increased $36.8 million, or 11 percent, due primarily to a $30 million increase in transportation revenue and a $3 million increase in storage revenue resulting primarily from new rates effective in the first quarter of 2007. In addition, revenues increased $3 million due to exchange imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses increased $18 million, or 10 percent, due primarily to:

An increase in depreciation expense of $7 million due to property additions;

An increase in personnel costs of $4 million;

The absence of a $3 million credit to expense recorded in 2006 related to corrections of the carrying value of certain liabilities;

An increase in costs of $3 million associated with exchange imbalance settlements (offset in *revenues*).

SG&A expenses increased $4 million, or 12 percent, due primarily to a $5 million increase in property insurance expenses resulting from increased premiums on offshore facilities and a $2 million increase in information systems support costs. Partially offsetting these increases is a $5 million decrease in expense related to an adjustment to correct rent expense from prior periods.

The $15 million, or 11 percent, increase in *segment profit* is due primarily to $36.8 million higher revenues as previously discussed, partially offset by increases in *costs and operating expenses* and *SG&A expenses* as previously discussed.

Midstream Gas & Liquids

Overview of Three Months Ended March 31, 2007

Midstream s ongoing strategy is to safely and reliably 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 business by providing highly reliable service to our customers.

Significant events during the first three months of 2007 include the following:

Continued favorable commodity price margins

The actual realized natural gas liquid (NGL) per unit margins at our processing plants exceeded Midstream s rolling five-year average for the first three months of 2007. The geographic diversification of Midstream assets contributed significantly to our actual realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. The largest impact was realized at our western United States gas processing plants, which benefited from lower regional market natural gas prices. During 2006 and continuing through the first quarter of 2007, NGL production rebounded from levels experienced in fourth-quarter 2005 in response to improved gas processing spreads.

Table of Contents

Management s Discussion and Analysis (Continued)

Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

During the first quarter of 2007, we completed construction at our existing gas processing complex located near Opal, Wyoming, to add a fifth cryogenic gas processing train capable of processing up to 350 MMcf/d, bringing total Opal capacity to approximately 1,450 MMcf/d. This plant expansion was operational for approximately half of the quarter. We also have several expansion projects ongoing in the West region to lower field pressures and increase production volumes for our customers who continue robust drilling activities in the region.

In the first quarter of 2007, we began pre-construction activities on the proposed Perdido Norte project which includes oil and gas lines that would expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. Additionally, we intend to expand our Markham gas processing facility to adequately serve this new gas production. The project is estimated to cost approximately $480 million and be in service in the third quarter of 2009.

In March 2007, we announced plans to construct and operate a 450 MMcf/d natural gas processing plant in western Colorado s Piceance basin, where Exploration & Production has its most significant volume of natural gas production, reserves and development activity. Exploration & Production s existing Piceance basin processing plants are primarily designed to condition the natural gas to meet quality specifications for pipeline transmission, not to maximize the extraction of NGLs. We expect the Willow Creek facility will recover an additional 20,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2007

The following factors could impact our business in the remaining three quarters of 2007 and beyond.

As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last five quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. Forecasted domestic demand for ethylene and propylene, along with political instability in many of the key oil producing countries, currently support NGL margins continuing to exceed our rolling five-year average. As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies.

Margins in our olefins unit are highly dependent upon continued economic growth within the United States and any significant slow down in the economy would reduce the demand for the petrochemical products we produce in both Canada and the United States. Based on recent market price forecasts, we anticipate olefins unit margins to be at or slightly above 2006 levels.

Gathering and processing revenues at our facilities are expected to be at levels of previous years due to continued strong drilling activities in our core basins.

Revenues from deepwater production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.

We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services.

We continued construction of a 37-mile extension of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. This extension, estimated to cost approximately $200 million, is expected to be ready for service by the second quarter of 2008.

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 expect revenues from our deepwater production areas to decrease as volumes decline in 2007 and increase in 2008 as we expand our Devil s Tower infrastructure to serve the Blind Faith prospect.

We are currently negotiating with our customer in Venezuela to resolve approximately $16 million in past due invoices, before associated reserves, related to labor escalation charges. The customer is not disputing the index used to calculate these charges and we have calculated the charges according to the terms of the contract. The customer does, however, believe the index has resulted in an inequitable escalation over time. We believe the receivables, net of associated reserves, are fully collectible. Although we believe our negotiations will be successful, failure to resolve this matter could ultimately trigger default noncompliance provisions in the services agreement.

The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, continues to publicly declare that additional energy contracts will be unilaterally amended, and that privately held assets will be expropriated, escalating our concern regarding political risk in Venezuela.

We are conducting negotiations with the Jicarilla Apache Nation in northern New Mexico for the renewal of certain rights of way on reservation lands. The current right of way agreement, which covers certain gathering system assets in our West region, expired on December 31, 2006. We continue to operate our assets on these reservation lands pursuant to a special business license which lasts through June 30, 2007, while we conduct further discussions that could result in renewal of our rights of way, sale of the gathering assets on reservation lands or other options that might be in the mutual interest of both parties.

Table of Contents

Management s Discussion and Analysis (Continued)

Period-Over-Period Results

	Three months ended March 31,	
	2007	**2006**
	(Millions)	
Segment revenues	$ 995.4	$ 979.4
Segment profit		
Domestic gathering & processing	$ 123.4	$ 123.4
Venezuela	26.9	35.5
Other	24.6	7.5
Indirect general and administrative expense	(20.9)	(14.9)
Total	$ 154.0	$ 151.5

In order to provide additional clarity, our management s discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

Three months ended March 31, 2007 vs. three months ended March 31, 2006

The $16 million increase in *segment revenues* is largely due to a $50 million increase in the marketing of NGLs and olefins.

This increase was partially offset by:

A $19 million decrease in revenues from our olefins unit due primarily to a planned shut down of our Geismar ethane cracker for major maintenance;

A $5 million decrease in fee revenues including an $11 million decrease in deepwater gathering and production handling volumes, partially offset by an increase in other fee revenues;

A $10 million decrease in revenues associated with the production of NGLs and condensate.

Segment costs and expenses increased $10 million primarily as a result of:

A $37 million increase in NGL and olefin marketing purchases;

A $22 million increase in operating expenses including higher property insurance, gathering and plant fuel, and depreciation;

A $4 million increase in general and administrative costs due primarily to higher legal, information technology and consulting expenses.

These increases were partially offset by:

A $37 million decrease in costs associated with the production of NGLs and condensate due primarily to lower natural gas prices;

A $19 million decrease in costs associated with production in our olefins unit due to the planned shut down mentioned above.

The $2.5 million increase in Midstream s *segment profit* reflects higher NGL margins and higher margins related to the marketing of NGLs and olefins, partially offset by higher operating expenses. A more detailed analysis of the segment profit of Midstream s various operations is presented as follows.

Table of Contents

Management s Discussion and Analysis (Continued)

Domestic gathering & processing

The *domestic gathering and processing segment profit* is unchanged and includes a $19 million increase in the West region and a $19 million decrease in the Gulf Coast region.

The $19 million increase in our West region s *segment profit* primarily results from higher product margins and higher gathering and processing fee based revenues, partially offset by higher operating expenses and lower gains on the sale of assets. The significant components of this increase include the following:

NGL and condensate margins increased $33 million in the first quarter of 2007 compared to the same period in 2006. This increase was driven by a decrease in costs associated with the production of NGLs reflecting lower natural gas prices and higher volumes due primarily to new capacity on the fifth cryogenic train at our Opal plant, partially offset by a decrease in average per unit NGL prices. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense.

Gathering and processing fee revenues increased $3 million. Processing volumes are higher due to customers electing to take liquids and pay processing fees. Gathering fees are higher as a result of higher average per-unit gathering rates.

Operating expenses increased $13 million including $7 million in higher gathering and plant fuel due primarily to the expiration of a favorable gas purchase contract, $4 million in higher depreciation, $3 million in lower gas imbalance revaluation gains, and $2 million in higher operations and maintenance expenses, partially offset by $3 million in lower system losses.

The first quarter of 2006 included a $4 million gain on the sale of idle gas treating equipment.

The $19 million decrease in the Gulf Coast region s *segment profit* is primarily a result of lower volumes from our deepwater facilities, lower NGL margins and higher operating expenses. The significant components of this increase include the following:

NGL margins decreased $6 million driven by a decrease in volumes resulting from lower NGL recoveries during the first quarter of 2007 caused by intermittent periods of uneconomical market commodity prices for ethane, partially offset by a decrease in costs associated with the production of NGLs.

Fee revenues from our deepwater assets decreased $11 million due primarily to higher than normal production flowing across our Devils Tower facility in the first quarter of 2006 driven by the initial flows from the Goldfinger and Triton fields and other volume declines.

Operating expenses increased $4 million primarily as a result of higher property insurance costs.

Venezuela

Segment profit for our Venezuela assets decreased $8.6 million. The decrease is primarily due to the absence of a $9 million gain from the settlement of a contract dispute in 2006, partially offset by $7 million of currency exchange gains in 2007. In addition, revenues and equity earnings are lower and operating expenses are slightly higher.

Other

The $17.1 million increase in *segment profit* of our other operations is due primarily to $5 million in higher margins related to the marketing of olefins, $8 million in higher margins related to the marketing of NGLs due to more favorable changes in pricing while product was in transit during 2007 as compared to 2006, an $8 million reversal of a maintenance accrual (see below), partially offset by the absence of a $4 million favorable transportation settlement in 2006.

Table of Contents

Management s Discussion and Analysis (Continued)

Effective January 1, 2007, we adopted FASB Staff Position (FSP) No. AUG AIR-1, *Accounting for Planned Major Maintenance Activities.* As a result, we recognized as other income an $8 million reversal of an accrual for major maintenance on our Geismar ethane cracker. We did not apply the FSP retrospectively because the impact to our first quarter 2007 and estimated full year 2007 earnings, as well as the impact to prior periods is not material. We have adopted the deferral method for accounting for these costs going forward.

Indirect general and administrative expense

The $6 million increase in indirect general and administrative expense is due primarily to higher employee, consulting, and legal expenses.

Power

Overview of Three Months Ended March 31, 2007

Power s operating results for the first three months of 2007 reflect unrealized mark-to-market losses primarily caused by a decrease in forward natural gas basis prices against a net long derivative position. Certain of these derivative positions are economic hedges but are not designated as hedges for accounting purposes. As a result, certain gains in accrual portfolios offset a portion of these losses and will be recovered once the realization of the physical underlying occurs. Power s results do not reflect, however, cash flows that Power realized in 2007 from hedges for which mark-to-market gains or losses had been previously recognized.

In the first quarter of 2007, 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 services that support our natural gas businesses. In February 2007, Power executed agreements to sell dispatch and tolling rights and supply natural gas in southern California for periods through 2011. These contracts mirror Power s rights under its California tolling agreement and represent up to 1,920 megawatts of power. The benefit of these contracts will primarily be realized in years subsequent to 2007.

Outlook for the Remainder of 2007

For the remainder of 2007, Power intends to service its customers needs while increasing the certainty of cash flows from its long-term tolling contracts by executing new long-term electricity and capacity sales contracts.

Power continues to apply cash flow hedge accounting to certain derivative contracts. As a result of cash flow hedge accounting, its future earnings may be less volatile. However, not all of Power s derivative contracts qualify for hedge accounting. Application of hedge accounting requires quantitative and qualitative analysis. To qualify for hedge accounting, Power must assess derivatives for their expected effectiveness in offsetting the risk being hedged. In addition, it must assess whether the hedged forecasted transaction is probable of occurring. If Power no longer expects the hedge to be highly effective, or if it believes that the hedged forecasted transaction is no longer probable of occurring, it would discontinue cash flow hedge accounting prospectively and recognize future changes in fair value directly to earnings.

Because certain derivative contracts qualifying for cash flow hedge accounting were previously marked-to-market through earnings prior to their designation as 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, future earnings may reflect losses from underlying transactions, such as natural gas purchases and power sales associated with our tolling contracts, which have been hedged by derivatives. A portion of the offsetting gains from these hedges, however, has already been recognized in prior periods under mark-to-market accounting. So, while earnings in a reported period may not reflect the full amount realized from our hedges, cash flows will continue to reflect the total amount from both the hedged transactions and the hedges. Power expects to continue to have positive cash flows from operations for 2007.

Management s Discussion and Analysis (Continued)

Even with the application of hedge accounting, Power s earnings will continue to reflect mark-to-market volatility from unrealized gains and losses resulting from:

- Market movements of commodity-based derivatives that represent economic hedges but which do not qualify for hedge accounting;
- 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;
- Market movements of commodity-based derivatives that are held for trading purposes.

The fair value of Power s tolling, full requirements, transportation, storage and transmission contracts is not reflected on the balance sheet since these contracts are not derivatives. Some of these contracts have a significant negative estimated fair value and could result in future losses. Power s estimate of fair value is based on internal valuation assumptions, which include assumptions of natural gas prices, electricity prices, price volatility, correlation of gas and electricity, and many other inputs. Some of these assumptions are readily available in the market, while others are not. Power s estimate of fair value may differ significantly from a third party s estimate.

Key factors that may influence Power s financial condition and operating results include:

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

Period-Over-Period Results

	Three months ended March 31,	
	2007	2006
	(Millions)	
Realized revenues	$ 1,845.7	$ 2,010.2
Net forward unrealized mark-to-market gains (losses)	(70.6)	43.0
Segment revenues	1,775.1	2,053.2
Cost of sales	1,834.2	2,076.7
Gross margin	(59.1)	(23.5)
Operating expenses	3.5	5.4
Selling, general and administrative expenses	18.9	(4.5)
Other income net	(.4)	(1.9)

Segment loss	$ (81.1)	$ (22.5)

Three months ended March 31, 2007 vs. three months ended March 31, 2006

The $164.5 million decrease in *realized revenues* is primarily due to a decrease in power and natural gas realized revenues. 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.

Table of Contents

Management s Discussion and Analysis (Continued)

Power and natural gas realized revenues decreased primarily due to a 10 percent decrease in power sales volumes and a 16 percent decrease in average natural gas sales prices, partially offset by an 11 percent increase in natural gas sales volumes. Power sales volumes decreased because certain long-term physical contracts were not replaced due to reducing the scope of trading activities subsequent to 2002.

Net forward unrealized mark-to-market gains (losses) represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that have not been designated as cash flow hedges and the impact of the ineffectiveness of cash flow hedges. The effect of a change in forward prices on natural gas contracts not designated as cash flow hedges and a decrease in gains from ineffectiveness primarily caused the $113.6 million unfavorable change in *net forward unrealized mark-to-market gains (losses).*

A decrease in forward natural gas basis prices during the first three months of 2007 caused losses on net forward gas basis purchase contracts, while a decrease in forward natural gas prices during the first three months of 2006 caused gains on net forward gas fixed price sales contracts. A lesser change in the locational price difference of the natural gas hedges and the hedged items in 2007 than in 2006 primarily caused the decrease in gains from ineffectiveness.

The $242.5 million decrease in Power s *cost of sales* is primarily due to a 14 percent decrease in power purchase volumes and a 16 percent decrease in average natural gas purchase prices.

The increase in Power s *SG&A expenses* in the first quarter of 2007 is primarily due to the absence of a $23.7 million gain from the sale of certain Enron receivables to a third party in first-quarter 2006.

The effect of a change in forward prices on natural gas contracts not designated as cash flow hedges, decreased gains from ineffectiveness, and the increase in *SG&A expenses*, offset by an improvement in accrual gross margin (defined as *realized revenues* less c*ost of sales*) primarily caused the $58.6 million increase in *segment loss.*

Other

Period-Over-Period Results

	Three months ended March 31,	
	2007	2006
	(Millions)	
Segment revenues	$ 6.8	$ 6.9
Segment profit	$ .7	$ 1.0

The results for our Other segment are comparable to the prior year.

Table of Contents

Management s Discussion and Analysis (Continued)

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of March 31, 2007. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

Net Assets (Liabilities) Trading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 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
$14	$ 1	$ (1)	$ (1)	$	$ 13

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Power s forecasted purchases of gas, its purchases and sales of power related to its long-term structured contracts and owned generation, and Exploration & Production s forecasted sales of natural gas production. Certain of Power s other derivatives have not been designated as or do not qualify as hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133). The chart below reflects the fair value of derivatives held for nontrading purposes as of March 31, 2007, for the Power, Exploration & Production, and Midstream businesses. Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $225 million as of March 31, 2007, which includes the existing fair value of the derivatives at the time of their designation as SFAS 133 cash flow hedges.

Net Assets (Liabilities) Nontrading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 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
$41	$ 215	$ 88	$ 31	$	$ 375

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance 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, 2007, we held collateral support, including letters of credit, of $613 million.

Management s Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts as of March 31, 2007, is summarized below.

Counterparty Type	**Investment Grade (a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 342.1	$ 344.0
Energy marketers and traders	468.2	2,094.8
Financial institutions	2,347.9	2,347.9
Other	21.7	25.5
	$ 3,179.9	4,812.2
Credit reserves		(15.9)
Gross credit exposure from derivatives		$ 4,796.3

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of March 31, 2007, is summarized below.

Counterparty Type	**Investment Grade (a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 146.3	$ 147.0
Energy marketers and traders	159.2	404.0
Financial institutions	197.6	197.6
Other	1.3	1.3
	$ 504.4	749.9
Credit reserves		(15.9)
Net credit exposure from derivatives		$ 734.0

(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.

39

Table of Contents

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition

Outlook

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. For the remainder of 2007, we expect to maintain liquidity from cash and cash equivalents and unused revolving credit facilities of at least $1 billion. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements through cash flow from operations, which is currently estimated to be between $2 billion and $2.3 billion in 2007, proceeds from debt issuances and sales of units of Williams Partners L.P., as well as cash and cash equivalents on hand as needed.

We entered 2007 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

- Exploration & Production will continue its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.

- Gas Pipeline will continue to expand its system to meet the demand of growth markets.

- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.4 billion to $2.6 billion in 2007, with approximately $1.9 billion to $2.1 billion to be incurred over the remainder of the year. As a result of increasing our development drilling program, $1.3 billion to $1.4 billion of the total estimated 2007 capital expenditures is related to Exploration & Production. Also within the total estimated expenditures for 2007 is approximately $215 million to $270 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, Exploration & Production has economically hedged the price of natural gas for approximately 172 MMcfe per day of its remaining expected 2007 production. In addition, Exploration & Production has collar agreements for each month of 2007 which hedge approximately 272 MMcfe per day of remaining expected 2007 production. Power has entered into various sales contracts that economically cover substantially all of its fixed demand obligations through 2010.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of March 31, 2007, we estimate our exposure to additional margin requirements through the remainder of 2007 to be no more than $498 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues. (See Note 8 of Notes to Consolidated Financial Statements.)

On April 4, 2007, Northwest Pipeline retired $175 million of 8.125 percent senior notes due 2010. Northwest Pipeline paid premiums of approximately $7.1 million in conjunction with the early debt retirement.

On April 5, 2007, Northwest Pipeline issued $185 million aggregate principal amount of 5.95 percent senior unsecured notes due 2017 to certain institutional investors in a private debt placement. (See Note 7 of Notes to Consolidated Financial Statements.)

Management s Discussion and Analysis (Continued)

Overview

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks in order to reduce margin requirements related to our hedging activities as well as lower transaction fees. Under the credit agreement, Exploration & Production is not required to post collateral as long as the value of its domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money positions on hedges entered into under the credit agreement. Exploration & Production is subject to additional covenants under the credit agreement including restrictions on hedge limits, the creation of liens, the incurrence of debt, the sale of assets and properties, and making certain payments, such as dividends, under certain circumstances.

Credit ratings

On March 19, 2007, Standard & Poor s raised our senior unsecured debt rating from a BB to a BB with a stable ratings outlook. With respect to Standard & Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify it s ratings with a + or a sign to show the obligor s relative standing within a major rating category.

Moody s Investors Service rates our senior unsecured debt at a Ba2 with a stable ratings outlook. With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. A Ba rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates th an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 ranking at the lower end of the category.

Fitch Ratings rates our senior unsecured debt at a BB+ with a stable ratings outlook. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. A BB rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Fitch may add a + or a sign to show the obligor s relative standing within a major rating category.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

Available Liquidity

	March 31, 2007 (Millions)
Cash and cash equivalents*	$ 1,811.2
Auction rate securities and other liquid securities	234.7
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	369.3
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,472.0
	$ 3,887.2

* *Cash and cash equivalents* includes $203.5 million of funds received from third parties as collateral. The obligation for these amounts is reported as *customer margin deposits payable* on the Consolidated Balance Sheet. Also included is $528 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** This facility is guaranteed by Williams Gas Pipeline Company, L.L.C. Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. Williams Partners L.P. has access to $75 million, to the extent not utilized by us, that we guarantee.

Management s Discussion and Analysis (Continued)

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities. If the credit rating of Northwest Pipeline or Transco is below investment grade for all credit rating agencies, they can only use their shelf registration statements to issue debt if such debt is guaranteed by us.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed.

In February 2007, Exploration & Production entered into a five-year unsecured credit agreement with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. (See Note 7 of Notes to Consolidated Financial Statements.)

Sources (Uses) of Cash

	Three months ended March 31, 2007	Three months ended March 31, 2006
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 299.8	$ 164.7
Financing activities	(116.1)	(155.8)
Investing activities	(641.1)	(491.1)
Decrease in cash and cash equivalents	$ (457.4)	$ (482.2)

Operating activities

Our *net cash provided by operating activities* for the three months ended March 31, 2007 increased from the same period in 2006. The increase in *net cash provided by operating activities* is largely due to a change in working capital, which is primarily due to a decrease in net cash outflows from *margin deposits and customer margin deposits payable* due mostly to changes in natural gas prices and our marginable positions.

Financing activities

During the first quarter of 2006, we paid $25.8 million in premiums for early debt retirement costs.

During the first quarter of 2007, we paid a quarterly dividend of 9 cents per common share, totaling $54.1 million, compared to a quarterly dividend of 7.5 cents per common share, totaling $44.6 million, for the first quarter of 2006.

Investing activities

During the first three months of 2007, capital expenditures totaled $509.1 million and were primarily related to Exploration & Production s increased drilling activity, mostly in the Piceance basin.

During the first three months of 2007, we purchased $173.2 million and received $44.6 million from the sale of auction rate securities. These are utilized as a component of our overall cash management program.

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

We have provided a guarantee for obligations of Williams Partners L.P. under the $1.5 billion unsecured revolving and letter of credit facility.

We have various other guarantees and commitments which are disclosed in Note 8 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Table of Contents

Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first three months of 2007. See Note 7 of Notes to Consolidated Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, electricity and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations, including correlations 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 and nonderivative energy-related contracts. 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 segregate our derivative contracts into trading and nontrading 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 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. Our value at risk for contracts held for trading purposes was approximately $2 million at March 31, 2007, and $1 million at December 31, 2006.

Nontrading

Our nontrading portfolio consists of derivative 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 and sales Electricity purchases and sales

Table of Contents

The value at risk for derivative contracts held for nontrading purposes was $13 million at March 31, 2007, and $12 million at December 31, 2006. Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Table of Contents

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 15d-15(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 2007 Changes in Internal Controls Over Financial Reporting

There have been no changes during first-quarter 2007 that have materially affected, or are reasonably likely to materially affect, our Internal Controls over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 8. 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 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2006 includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed except as set forth below:

The outcome of pending rate cases to set the rates we can charge customers on certain of our pipelines might result in rates that do not provide an adequate return on the capital we have invested in those pipelines.

In 2006 we filed rate cases with the FERC to request changes to the rates we charge on Northwest Pipeline and Transco. Northwest Pipeline has settled its rate case but Transco s case is still pending and the outcome is uncertain. There is a risk that rates set by the FERC will be lower than is necessary to provide Transco with an adequate return on the capital we have invested in these assets. There is also the risk that higher rates will cause our customers to look for alternative ways to transport their natural gas.

Item 6. Exhibits

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

Exhibit 1.1 Summary of Non-Management Director Compensation Action.

Exhibit 3.2 Restated By-Laws (filed as Exhibit 3.2 to our current report on Form 8-K filed January 31, 2007).

Exhibit 4.1 Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed as Exhibit 4.1 to Northwest Pipeline Corporation s (Commission File number 001-07414) current report on Form 8-K filed April 5, 2007).

Exhibit 10.1 Form of 2007 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our current report on Form 8-K filed March 1, 2007).

Exhibit 10.2 Form of 2007 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our current report on Form 8-K filed March 1, 2007).

Exhibit 10.3 Form of 2007 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our current report on Form 8-K filed March 1, 2007).

Exhibit 10.4 Credit Agreement, dated as of February 23, 2007, among Williams Production RMT Company, Williams Production Company, LLC, the banks from time to time parties thereto, Citibank, N.A., as administrative agent, Citigroup Energy Inc., as computation agent, and Calyon New York Branch, as collateral agent and as PV determination agent (filed as Exhibit 10.41 to our Form 10-K for the fiscal year ended December 31, 2006).

Exhibit 10.5 Registration Rights Agreement, dated as of April 5, 2007, among Northwest Pipeline Corporation and Greenwich Capital Markets, Inc. and Banc of America Securities LLC, acting on behalf of themselves and the several initial purchasers listed on Schedule I thereto (filed as Exhibit 10.1 to Northwest Pipeline Corporation s (Commission File number 001-07414) current report on Form 8-K filed April 5, 2007).

Exhibit 12 Computation of Ratio of Earnings to Fixed Charges.

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/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and Principal Accounting Officer)

May 3, 2007