WILLIAMS COMPANIES INC
Form 10-Q
August 07, 2008

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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 June 30, 2008

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 or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER, TULSA, OKLAHOMA	74172
(Address of principal executive offices)	(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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 July 31, 2008

Common Stock, $1 par value	576,266,231 Shares

The Williams Companies, Inc.
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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 or results of operations;
- seasonality of certain business segments;
- natural gas and natural gas liquids prices and demand.

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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 project. 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 future changes in our credit ratings;
- risks associated with future weather conditions;
- 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 to and do not intend to update the above list 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, 2007, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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

(Dollars in millions, except per-share amounts)	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
Revenues:				
Exploration & Production	$ 976	$ 539	$ 1,724	$ 1,022
Gas Pipeline	406	415	819	786
Midstream Gas & Liquids	1,754	1,243	3,311	2,245
Gas Marketing Services	2,010	1,394	3,660	2,682
Other	6	6	12	13
Intercompany eliminations	(1,423)	(773)	(2,573)	(1,556)
Total revenues	3,729	2,824	6,953	5,192
Segment costs and expenses:				
Costs and operating expenses	2,747	2,180	5,120	4,023
Selling, general and administrative expenses	131	108	242	210
Other income net	(35)	(18)	(152)	(36)
Total segment costs and expenses	2,843	2,270	5,210	4,197
General corporate expenses	42	36	84	76
Operating income (loss):				
Exploration & Production	490	204	917	387
Gas Pipeline	164	170	334	311
Midstream Gas & Liquids	279	243	517	390
Gas Marketing Services	(46)	(63)	(25)	(93)
Other	(1)			
General corporate expenses	(42)	(36)	(84)	(76)
Total operating income	844	518	1,659	919
Interest accrued	(165)	(172)	(330)	(344)
Interest capitalized	16	7	24	12
Investing income	55	66	110	118
Minority interest in income of consolidated subsidiaries	(63)	(25)	(102)	(39)
Other income net		2	5	4
Income from continuing operations before income taxes	687	396	1,366	670
Provision for income taxes	268	153	531	257

Income from continuing operations	419	243	835	413
Income from discontinued operations	18	190	102	154
Net income	$ 437	$ 433	$ 937	$ 567
Basic earnings per common share:				
Income from continuing operations	$ .72	$ .40	$ 1.43	$ .69
Income from discontinued operations	.03	.32	.17	.26
Net income	$. 75	$. 72	$ 1.60	$. 95
Weighted-average shares (thousands)	583,400	599,518	584,459	598,778
Diluted earnings per common share:				
Income from continuing operations	$ .70	$ .40	$ 1.40	$ .68
Income from discontinued operations	.03	.31	.17	.25
Net income	$. 73	$. 71	$ 1.57	$. 93
Weighted-average shares (thousands)	596,187	613,172	597,404	612,325
Cash dividends declared per common share	$ .11	$ .10	$. 21	$ .19

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	June 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,937	$ 1,699
Accounts and notes receivable (net of allowance of $33 at June 30, 2008 and $27 at December 31, 2007)	1,642	1,192
Inventories	341	209
Derivative assets	5,435	1,736
Assets of discontinued operations	70	185
Deferred income taxes	176	199
Other current assets and deferred charges	335	318
Total current assets	9,936	5,538
Investments	942	901
Property, plant and equipment net	16,933	15,981
Derivative assets	1,658	859
Goodwill	1,011	1,011
Other assets and deferred charges	736	771
Total assets	$ 31,216	$ 25,061
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,473	$ 1,131
Accrued liabilities	1,350	1,158
Derivative liabilities	6,117	1,824
Liabilities of discontinued operations	61	175
Long-term debt due within one year	83	143
Total current liabilities	9,084	4,431
Long-term debt	7,869	7,757
Deferred income taxes	3,026	2,996
Derivative liabilities	2,063	1,139
Other liabilities and deferred income	915	933
Contingent liabilities and commitments (Note 12)		
Minority interests in consolidated subsidiaries	607	1,430
Stockholders equity:		
	611	608

Common stock (960 million shares authorized at $1 par value; 611 million issued at June 30, 2008 and 608 million shares issued at December 31, 2007)		
Capital in excess of par value	8,042	6,748
Retained earnings (deficit)	521	(293)
Accumulated other comprehensive loss	(590)	(121)
	8,584	6,942
Less treasury stock, at cost (32 million shares of common stock at June 30, 2008 and 22 million shares of common stock at December 31, 2007)	(932)	(567)
Total stockholders equity	7,652	6,375
Total liabilities and stockholders equity	$ 31,216	$ 25,061

See accompanying notes.

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

(Dollars in millions)	Six months ended June 30, 2008	2007
OPERATING ACTIVITIES:		
Net income	$ 937	$ 567
Adjustments to reconcile to net cash provided by operations:		
Reclassification of deferred net hedge gains related to sale of power business		(429)
Depreciation, depletion and amortization	620	517
Provision for deferred income taxes	329	331
Provision for loss on investments, property and other assets	4	133
Net gain on disposition of assets	(6)	(18)
Gain on sale of contractual production rights	(148)	
Minority interest in income of consolidated subsidiaries	102	39
Amortization of stock-based awards	34	33
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(361)	(157)
Inventories	(129)	10
Margin deposits and customer margin deposits payable	183	19
Other current assets and deferred charges	(53)	(12)
Accounts payable	172	42
Accrued liabilities	102	(124)
Changes in current and noncurrent derivative assets and liabilities	(18)	140
Other, including changes in noncurrent assets and liabilities	(2)	(107)
Net cash provided by operating activities	1,766	984
FINANCING ACTIVITIES:		
Proceeds from long-term debt	674	184
Payments of long-term debt	(619)	(297)
Proceeds from issuance of common stock	23	29
Proceeds from sale of limited partner units of consolidated partnerships	362	
Tax benefit of stock-based awards	18	16
Dividends paid	(123)	(114)
Purchase of treasury stock	(359)	
Dividends and distributions paid to minority interests	(54)	(37)
Changes in restricted cash	(30)	(3)
Changes in cash overdrafts	(23)	22
Other net	(4)	(7)
Net cash used by financing activities	(135)	(207)
INVESTING ACTIVITIES:		
Property, plant and equipment:		

Capital expenditures	(1,561)	(1,227)
Net proceeds from dispositions	9	(10)
Changes in accounts payable and accrued liabilities	40	46
Proceeds from sale of discontinued operations	8	
Purchases of investments/advances to affiliates	(67)	(24)
Purchases of auction rate securities		(250)
Proceeds from sales of auction rate securities		105
Proceeds from sale of contractual production rights	148	
Proceeds from dispositions of investments and other assets	23	46
Other net	7	7
Net cash used by investing activities	(1,393)	(1,307)
Increase (decrease) in cash and cash equivalents	238	(530)
Cash and cash equivalents at beginning of period	1,699	2,269
Cash and cash equivalents at end of period	$ 1,937	$ 1,739

See accompanying notes.

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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 June 30, 2008, and results of operations for the three and six months ended June 30, 2008 and 2007 and cash flows for the six months ended June 30, 2008 and 2007.

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

Discontinued Operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our former power business as discontinued operations. (See Note 3.) These operations included a 7,500-megawatt portfolio of power-related contracts that was sold in 2007 to Bear Energy, LP, a unit of the Bear Stearns Company, Inc., and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton) that was sold in March 2008, in addition to other power-related assets.

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

Master Limited Partnerships

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner 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, Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP (Northwest Pipeline). Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. is consolidated within our Gas Pipeline segment due to our control through the general partner.

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Notes (Continued)

Note 3. Discontinued Operations

The summarized results of discontinued operations and summarized assets and liabilities of discontinued operations primarily reflect our former power business except where noted otherwise.

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the three and six months ended June 30, 2008 and 2007.

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Revenues	$ 5	$ 1,023	$ 5	$ 1,507
Income from discontinued operations before income taxes	31	433	163	376
Impairments		(126)		(126)
Provision for income taxes	(13)	(117)	(61)	(96)
Income from discontinued operations	$ 18	$ 190	$ 102	$ 154

Income from discontinued operations before income taxes for the three months ended June 30, 2008, includes a $10 million charge associated with a settlement primarily related to the sale of natural gas liquids pipeline systems in 2002 (see Note 12), a charge of $10 million associated with an oil purchase contract related to our former Alaska refinery, and a $54 million gain related to the favorable resolution of a matter involving pipeline transportation rates associated with our former Alaska operations.

Income from discontinued operations before income taxes for the six months ended June 30, 2008, includes both of the $10 million charges discussed above, $54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank (see Note 12), and $128 million of gains related to the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations.

Income from discontinued operations before income taxes for the three and six months ended June 30, 2007, includes a gain of $429 million (reported in *revenues* of discontinued operations) associated with the reclassification of deferred net hedge gains from *accumulated other comprehensive income* to earnings in second-quarter 2007. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold were probable of not occurring. The six months ended June 30, 2007, also includes unrealized mark-to-market losses of $23 million.

The *impairments* for the three and six months ended June 30, 2007, include $111 million related to the carrying value of certain derivative contracts for which we had previously elected the normal purchases and normal sales exception under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and, accordingly, were no longer recording at fair value, and $15 million related to our natural gas-fired electric generating plant near Hazleton, Pennsylvania. These impairments were based on our comparison of the carrying value to the estimate of fair value less cost to sell.

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of June 30, 2008 and December 31, 2007. The June 30, 2008, and December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to Bear Energy, LP, entirely offset by reciprocal positions with Bear Energy, LP. We continue to pursue assignment of the remaining contracts. The December 31, 2007, balance of *property, plant and equipment net* includes Hazleton. These assets were sold in a March 2008 transaction for $8 million.

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Notes (Continued)

	June 30, 2008	December 31, 2007
	(Millions)	
Derivative assets	$ 30	$ 114
Accounts receivable net	35	55
Other current assets	5	3
Total current assets	70	172
Property, plant and equipment net		8
Other noncurrent assets		5
Total noncurrent assets		13
Total assets	$ 70	$ 185
Derivative liabilities	$ 30	$ 114
Other current liabilities	31	61
Total current liabilities	61	175
Total liabilities	$ 61	$ 175

Note 4. Asset Sales and Other Accruals

The following table presents significant gains from asset sales and other accruals or adjustments reflected in *other income net* within *segment costs and expenses.*

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Exploration & Production				
Gain on sale of contractual right to an international production payment	$(30)	$	$(148)	$
Gas Pipeline				
Change in estimate related to a regulatory liability		(17)		(17)

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. In the first quarter of 2008, we received $118 million in cash, with the remainder placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of $118 million in the first quarter of 2008 related to the initial cash received. In the second quarter of 2008, the remaining cash was received from escrow and recognized as income.

Investing income within our Other segment includes gains from the sales of cost-based investments of $6 million and $9 million, respectively, for the three and six months ended June 30, 2008, and $14 million of similar gains for the three and six months ended June 30, 2007.

Note 5. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
	(Millions)		(Millions)	
Current:				
Federal	$ 158	$ (6)	$ 266	$ (3)
State	28	3	45	1
Foreign	15	16	29	25
	201	13	340	23
Deferred:				
Federal	61	126	163	201
State	3	9	19	22
Foreign	3	5	9	11
	67	140	191	234
Total provision	$ 268	$ 153	$ 531	$ 257

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Notes (Continued)

The effective income tax rates for the three and six months ended June 30, 2008 and 2007, are greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective tax rate for the three and six months ended June 30, 2007, was partially offset by a benefit recognized based on a favorable private letter ruling received from the Internal Revenue Service concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible.

During the next twelve months, we do not expect settlement of any unrecognized tax benefit associated with domestic or international matters under audit to have a material impact on our financial position.

Note 6. Earnings Per Common Share from Continuing Operations

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

	Three months ended June 30, 2008	Three months ended June 30, 2007	Six months ended June 30, 2008	Six months ended June 30, 2007
	(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)	$ 419	$ 243	$ 835	$ 413
Basic weighted-average shares (2)	583,400	599,518	584,459	598,778
Effect of dilutive securities:				
Nonvested restricted stock units (3)	1,242	1,522	1,354	1,443
Stock options	4,227	4,810	4,273	4,780
Convertible debentures	7,318	7,322	7,318	7,324
Diluted weighted-average shares	596,187	613,172	597,404	612,325
Earnings per common share from continuing operations:				
Basic	$ .72	$ .40	$ 1.43	$ .69
Diluted	$ .70	$ .40	$ 1.40	$ .68

(1) The three and six months ended June 30, 2008 and 2007 each include $1 million 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) Since third-quarter 2007, we have purchased approximately 26 million shares of our common stock under a stock repurchase program (see Note 11).

(3) The nonvested restricted stock units outstanding at June 30, 2008, will vest over the period from July 2008 to January 2012.

The table below includes information related to stock options that were outstanding at June 30 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the second quarter weighted-average market price of our common shares.

	June 30, 2008	June 30, 2007
Options excluded (millions)	.4	2.2
Weighted-average exercise prices of options excluded	$ 41.87	$ 37.21
Exercise price ranges of options excluded	$ 37.88 - $42.29	$ 31.55 - $42.29
Second quarter weighted-average market price	$ 37.38	$ 30.07

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Notes (Continued)

Note 7. Employee Benefit Plans

Net periodic benefit expense for the three and six months ended June 30, 2008 and 2007 are as follows:

	Pension Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic pension expense:				
Service cost	$ 6	$ 6	$ 11	$ 12
Interest cost	16	14	30	27
Expected return on plan assets	(19)	(18)	(39)	(36)
Amortization of net actuarial loss	5	5	7	9
Net periodic pension expense	$ 8	$ 7	$ 9	$ 12

	Other Postretirement Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic other postretirement benefit expense:				
Service cost	$	$	$ 1	$ 1
Interest cost	5	4	9	8
Expected return on plan assets	(3)	(3)	(6)	(6)
Regulatory asset amortization	1	2	2	3
Net periodic other postretirement benefit expense	$ 3	$ 3	$ 6	$ 6

During the six months ended June 30, 2008, we contributed $21 million to our pension plans and $7 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $21 million to our pension plans in the remainder of 2008 for a total of approximately $42 million. We presently anticipate making additional contributions of approximately $8 million to our other postretirement benefit plans in 2008 for a total of approximately $15 million.

Note 8. Inventories

Inventories at June 30, 2008 and December 31, 2007 are as follows:

	June 30, 2008	December 31, 2007
	(Millions)	
Natural gas liquids (NGLs)	$ 131	$ 66
Natural gas in underground storage	106	45
Materials, supplies and other	104	98
	$ 341	$ 209

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At June 30, 2008, no loans are outstanding under our credit facilities. Letters of credit issued under our credit facilities are:

	Letters of Credit at June 30, 2008 (Millions)
$500 million unsecured credit facilities	$
$700 million unsecured credit facilities	$ 319
$1.5 billion unsecured credit facility	$ 28

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Notes (Continued)

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. In June 2008, the agreement was extended through December 2013.

Issuances and retirements

On January 15, 2008, Transcontinental Gas Pipe Line Corporation (Transco) retired $100 million of 6.25 percent senior unsecured notes due January 15, 2008, with proceeds borrowed on our $1.5 billion unsecured credit facility.

On April 15, 2008, Transco retired a $75 million adjustable rate unsecured note due April 15, 2008, with proceeds borrowed under our $1.5 billion unsecured credit facility.

On May 22, 2008, Transco issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. A portion of these proceeds was used to repay Transco s $100 million and $75 million loans from January 2008 and April 2008, respectively, under our $1.5 billion unsecured credit facility.

On May 22, 2008, Northwest Pipeline issued $250 million aggregate principal amount of 6.05 percent senior unsecured notes due 2018 to certain institutional investors in a Rule 144A private debt placement. These proceeds were used to repay Northwest Pipeline s $250 million loan from December 2007 under our $1.5 billion unsecured credit facility.

Registration payment arrangements

Under the terms of Transco s $250 million 6.05 percent senior unsecured notes and Northwest Pipeline s $250 million 6.05 percent senior unsecured notes mentioned above, both parties are obligated to file an exchange offer registration statement offering to exchange the notes for a new issue of substantially identical notes (except they will not be subject to transfer restrictions) to be registered under the Securities Act of 1933, as amended, within 180 days after closing (May 22, 2008). Transco and Northwest Pipeline are obligated to use commercially reasonable efforts to cause such registration statements to be declared effective within 270 days after closing and to consummate the exchange offers within 30 business days after such effective date. They may also be required to provide shelf registration statements to cover resales of the notes under certain circumstances. If either party fails to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of the default, increasing by an additional 0.25 percent per annum with respect to each subsequent 90-day period thereafter up to a maximum amount for all such defaults of 0.5 percent annually.

Note 10. Fair Value Measurements

Adoption of SFAS No. 157

SFAS No. 157, Fair Value Measurements (SFAS 157), 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. On January 1, 2008, we applied SFAS 157 for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. Upon applying SFAS 157, we changed our valuation methodology to consider our nonperformance risk in estimating the fair value of our liabilities. The initial adoption of SFAS 157 had no material impact on our Consolidated Financial Statements. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. SFAS 157 requires two distinct transition approaches: (1) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (2) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable for all other instruments. Upon adopting SFAS 157,

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Notes (Continued)

we applied a prospective transition as we did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings.

Fair value is the price that would be received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market based measurement considered from the perspective of a market participant. We use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We primarily apply a market approach for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange-traded, including certain instruments that were part of sales transactions in 2007 and remain to be assigned to the purchaser. These unassigned instruments are entirely offset by reciprocal positions entered into directly with the purchaser. These reciprocal positions have also been included in Level 1.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 primarily consists of over-the-counter (OTC) instruments such as forwards and swaps.

Level 3 Includes inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value. Instruments in this category primarily include OTC options.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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Notes (Continued)

The following table sets forth by level within the fair value hierarchy our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements at June 30, 2008 Using:

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(Millions)		
Assets:				
Energy derivatives	$ 3,207	$ 3,659	$ 227	$ 7,093
Other assets			10	10
Total assets	$ 3,207	$ 3,659	$ 237	$ 7,103
Liabilities:				
Energy derivatives	$ 3,129	$ 4,183	$ 868	$ 8,180
Total liabilities	$ 3,129	$ 4,183	$ 868	$ 8,180

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value also incorporates other factors including the credit standing of the counterparties involved, our nonperformance risk on our liabilities, the impact of credit enhancements (such as cash deposits and letters of credit) and the time value of money.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Contracts for which fair value can be estimated from executed transactions or broker quotes corroborated by other market data are generally classified within Level 2. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Certain instruments trade in less active markets with lower availability of pricing information requiring valuation models using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The fair value of options is estimated using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas other model inputs, such as implied volatility by location, is unobservable and requires judgment in estimating. The instruments included in Level 3 at June 30, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled.

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Notes (Continued)

The following tables set forth a reconciliation of changes in the fair value of net derivatives and other assets classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs
Three Months Ended June 30, 2008

	Net Derivatives	Other Assets
	(Millions)	
Balance as of April 1, 2008	$ (186)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	(32)	
Included in *other comprehensive loss* (See Note 13)	(483)	
Purchases, issuances, and settlements	61	
Transfers in/out of Level 3	(1)	
Balance as of June 30, 2008	$ (641)	$ 10
Unrealized losses included in *income from continuing operations* relating to instruments still held at June 30, 2008	$ (45)	$

Level 3 Fair Value Measurements Using Significant Unobservable Inputs
Six Months Ended June 30, 2008

	Net Derivatives	Other Assets
	(Millions)	
Balance as of January 1, 2008	$ (14)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	(29)	
Included in *other comprehensive loss* (See Note 13)	(660)	
Purchases, issuances, and settlements	64	
Transfers in/out of Level 3	(2)	
Balance as of June 30, 2008	$ (641)	$ 10
Unrealized losses included in *income from continuing operations* relating to instruments still held at June 30, 2008	$ (44)	$

Realized and unrealized gains (losses) included in *income from continuing operations* for the above period are reported in *revenues* in our Consolidated Statement of Income.

Note 11. Stockholders Equity

In the first six months of 2008, we purchased ten million shares of our common stock for $365 million under our $1 billion common stock repurchase program at an average cost of $36.70 per share. Since the program s inception in third-quarter 2007 through June 30, 2008, we have purchased 26 million shares of our common stock for $891 million (including transaction costs). This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet. Our Consolidated Statement of Cash Flows reflects $359 million of treasury stock purchases for the six months ended June 30, 2008, due to a purchase made in late June 2008 that was not settled until July 2008. In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors. Our overall average cost per share under the completed repurchase program was $34.74.

At December 31, 2007, we held all of Williams Partners L.P. s seven million subordinated units outstanding. In February 2008, these subordinated units were converted into common units of Williams Partners L.P. due to the achievement of certain financial targets that resulted in the early termination of the subordination period. While these subordinated units were outstanding, other issuances of partnership units by Williams Partners L.P. had preferential rights and the proceeds from these issuances in excess of the book basis of assets acquired by Williams Partners L.P. were therefore reflected as minority interest on our Consolidated Balance Sheet rather than as equity. Due to the conversion of the subordinated units, these original issuances of partnership units no longer have preferential rights and now represent the lowest level of equity securities issued by Williams Partners L.P. In

Notes (Continued)

accordance with our policy regarding the issuance of equity of a consolidated subsidiary, such issuances of nonpreferential equity are accounted for as capital transactions and no gain or loss is recognized. Therefore, as a result of the first-quarter conversion, we recognized a decrease to minority interest and a corresponding increase to stockholders equity of approximately $1.2 billion.

Note 12. Contingent Liabilities

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 June 30, 2008, which we believe is adequate for any refunds that may be required.

Issues Resulting from California Energy Crisis

Our former power business was 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 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 June 2008 U.S. Supreme Court decision, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds depending on the results of further proceedings at the FERC. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. While we are not a party to the cases involved in the U.S. Supreme Court decision, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to 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 the counterparty to the contracts described above and 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 including interest on refund amounts that we might owe to settling and 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 $24 million at June 30, 2008. Collection of the interest and the payment of interest on refund amounts from the escrow accounts 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 and continue to be made. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us. Due to the ongoing proceedings and challenges, the final refund calculation has not been made and aspects of the refund calculation process remain unsettled.

Reporting of Natural Gas-Related Information to Trade Publications

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

State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use.

Notes (Continued)

Class action litigation and other litigation originally filed 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 Tennessee state court s 2007 dismissal of their case. The Missouri case has been remanded to Missouri state court. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada. On February 19, 2008, the federal court granted summary judgment in the Colorado case in favor of us and most of the other defendants. We expect that the Colorado plaintiffs will appeal.

Mobile Bay Expansion

In 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 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. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. Certain parties filed appeals in federal court seeking to overturn the FERC s ruling on the rolled-in rates. On April 2, 2008, Gas Marketing Services executed an agreement that settled this matter for $10 million, which was accrued in 2007.

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 parties 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 June 30, 2008, we had accrued liabilities of $5 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. We expect that these costs will be recoverable through Transco s rates.

Beginning in the mid-1980s, 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 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. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington s current environmental standards. At June 30, 2008, we have accrued liabilities of $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. We currently do not know if our interstate gas pipelines will be impacted. If they are, we will likely incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet the new regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

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Notes (Continued)

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At June 30, 2008, we have accrued liabilities totaling $6 million for these costs.

Williams Production RMT Company performed voluntary audits of its 2006 and 2007 compliance with state and federal air regulations. In June 2007, pursuant to Colorado s audit immunity privilege law, we disclosed to the Colorado Department of Public Health and Environment (CDPHE) that certain aspects of our facilities were not in compliance. We also described corrective actions that had or would be taken to remedy the issues. The CDPHE denied our request for penalty immunity and proposed a penalty. In a separate matter, the CDPHE issued a Notice of Violation (NOV) to Williams Production RMT Company in 2006 related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. We settled both of these matters with the CDHPE in June 2008 by agreeing to pay a $93,300 civil penalty and make a $373,200 contribution to a state environmental program.

In April 2007, the CDPHE issued an 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. The Rifle Station facility had been shut down prior to our receipt of the NOV and, except for some minor operations, remains closed. We settled with the CDPHE in June 2008 and will pay an $11,200 civil penalty and a $44,800 contribution to a state environmental program.

In April 2007, the New Mexico Environment Department s Air Quality Bureau (NMED) issued an NOV to Williams Four Corners, LLC (Four Corners) that alleged various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. In December 2007 the NMED proposed a penalty of approximately $3 million. We are discussing the basis for and the scope of the proposed penalty with the NMED.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA s investigation of our compliance with the Clean Air Act. On March 28, 2008, the EPA issued NOVs alleging violations of Clear Air Act requirements at these compressor stations. We met with the EPA in May 2008 and submitted our response denying the allegations in June 2008.

Former operations, including operations classified as discontinued

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

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At June 30, 2008, we have accrued liabilities of $9 million for such excess costs.

Other

At June 30, 2008, we have accrued environmental liabilities of $16 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;

Notes (Continued)

Former exploration and production and mining operations.

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.

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. The amount of any possible liability cannot be reasonably estimated at this time.

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 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.

In August 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 state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit 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 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in

Notes (Continued)

2005, denying liability for the damages claimed. Trial in this case has been set for November 2008. The amount of any possible liability cannot be reasonably estimated at this time.

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 complaints of the WilTel securities holders and of our securities holders added numerous claims. 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.

On July 6, 2007, the court granted various defendants motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs appealed the court s judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court s judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), has been 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. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when we sold WAPI s interests in the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order, which the RCA adopted. On February 15, 2008, the Alaska Supreme Court upheld the RCA s order and on March 16, 2008, the D.C. Circuit Court of Appeals upheld the FERC s order. We have paid substantially all amounts invoiced by the Quality Bank Administrator and third parties, except certain disputed amounts which remain accrued. Certain counterparties might file further appeals of the FERC s order with the U.S. Supreme Court.

We believe that the likelihood of successful appeal by the counterparties is remote, considering the relevant facts and circumstances related to this matter, including the favorable 2008 D.C. Circuit Court of Appeals rulings, and our assessment of the counterparties limited remaining options. As a result, during the first quarter of 2008 we reduced remaining amounts accrued in excess of our estimated remaining obligation by $54 million.

Redondo Beach taxes

In February 2005, we and AES Redondo Beach, L.L.C. received a tax assessment letter 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 were 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 us 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. In December 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

Notes (Continued)

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. In April 2007, we paid the city the protested amount of approximately $57 million in order to pursue our appeal. We and AES Redondo Beach also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment.

The city s most recent assessment of our liability for the periods from 1998 through September 2007 was approximately $72 million (inclusive of interest and penalties). In connection with the sale of our power business (see Note 2), we settled our dispute with AES Redondo Beach by equally sharing, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid under protest. We continued to believe that a contingent loss in this matter was not probable.

On March 14, 2008, the Los Angeles Superior Court decided in our favor, finding, among other things, that the challenged assessment was not supported by the city s utility users tax ordinance and was issued in violation of the California State Constitution. On April 2, 2008, the city appealed the decision. On July 1, 2008, we and the city settled all disputes, and the city subsequently refunded all tax payments made under protest plus half of the earned interest on those amounts. We shared this refund with AES Redondo Beach pursuant to our separate settlement. As a result of the settlement, we will recognize interest income of $1 million in the third quarter of 2008.

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. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25 million, all of which have been accrued as of June 30, 2008. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs claims for attorneys fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. Gulf Liquids, Gulsby, Gulsby-Bay, and NAICO are appealing the judgment. If the judgment is upheld on appeal, our liability will be substantially less than the amount of our accrual for these matters.

Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary Williams Production RMT Company for additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. We disputed the DOA s interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. The SBOE did not award interest on the assessment. We estimate that the amount of the additional severance and ad valorem taxes to be approximately $4 million. We appealed the SBOE decision to the Wyoming Supreme Court and oral argument is scheduled for August 12, 2008. 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 $20 million to $23 million in additional taxes and interest from January 1, 2003 through June 30, 2008.

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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.

Certain other royalty matters are currently being litigated by a federal regulatory agency and another Colorado producer. Although we are not a party to the litigation, the final outcome of that case might lead to a future unfavorable impact on our results of operations.

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 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleged that we breached certain warranties under the purchase and sale agreement and sought approximately $18 million in damages and our specific performance under certain guarantees. The dispute was settled in June 2008 and all court cases have been dismissed.

At June 30, 2008, 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 our 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.

Guarantees

In connection with agreements executed to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers that 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, Gas Marketing Services, 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 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 $43 million at June 30, 2008. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is $39 million at June 30, 2008.

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.

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN, an equity method investee. These expire in January 2009 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 June 30, 2008.

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Notes (Continued)

Note 13. Comprehensive Income

Comprehensive income is as follows:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Net income	$ 437	$ 433	$ 937	$ 567
Other comprehensive loss:				
Net unrealized gains (losses) on derivative instruments	(602)	111	(819)	121
Net reclassification into earnings of derivative instrument (gains) losses	59	(454)	79	(444)
Foreign currency translation adjustments	4	28	(17)	31
Amortization of pension benefits net actuarial loss	5	5	7	9
Amortization of other postretirement benefits prior service cost	1	1	1	1
Other comprehensive loss before taxes	(533)	(309)	(749)	(282)
Income tax benefit on other comprehensive loss	205	129	280	120
Other comprehensive loss	(328)	(180)	(469)	(162)
Comprehensive income	$ 109	$ 253	$ 468	$ 405

Net unrealized gains (losses) 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 (losses) on derivative instruments* are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Net unrealized gains (losses) on:				
Forward natural gas purchases and sales	$ (546)	$ 119	$ (760)	$ 152
Forward natural gas liquids sales	(58)		(60)	
Forward power purchases and sales		(8)		(31)
Other derivative instruments	2		1	
	$ (602)	$ 111	$ (819)	$ 121

Net reclassification into earnings of derivative instrument (gains) losses for the three and six months ended June 30, 2007, includes a gain of $429 million. This reclassification was based on the determination that the forecasted transactions related to the derivative cash flow hedges being sold as part of the sale of our power business were probable of not occurring.

Note 14. 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 partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P., are consolidated within our Midstream and Gas Pipeline segments, respectively. (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.

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.

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Notes (Continued)

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

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Three months ended June 30, 2008							
Segment revenues:							
External	$ (81)	$ 395	$ 1,761	$ 1,653	$ 1	$	$ 3,729
Internal	1,057	11	(7)	357	5	(1,423)	
Total revenues	$ 976	$ 406	$ 1,754	$ 2,010	$ 6	$ (1,423)	$ 3,729
Segment profit (loss)	$ 496	$ 179	$ 295	$ (46)	$ (1)	$	$ 923
Less equity earnings	6	15	16				37
Segment operating income (loss)	$ 490	$ 164	$ 279	$ (46)	$ (1)	$	886
General corporate expenses							(42)
Total operating income							$ 844
Three months ended June 30, 2007							
Segment revenues:							
External	$ (14)	$ 408	$ 1,232	$ 1,196	$ 2	$	$ 2,824
Internal	553	7	11	198	4	(773)	
Total revenues	$ 539	$ 415	$ 1,243	$ 1,394	$ 6	$ (773)	$ 2,824
Segment profit (loss)	$ 209	$ 180	$ 251	$ (63)	$	$	$ 577
Less equity earnings	5	10	8				23
Segment operating income (loss)	$ 204	$ 170	$ 243	$ (63)	$	$	554
General corporate expenses							(36)
Total operating income							$ 518

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Six months ended June 30, 2008							
Segment revenues:							
External	$ (127)	$ 797	$ 3,305	$ 2,973	$ 5	$	$ 6,953

Internal	1,851	22	6	687	7	(2,573)	
Total revenues	$ 1,724	$ 819	$ 3,311	$ 3,660	$ 12	$ (2,573)	$ 6,953
Segment profit (loss)	$ 926	$ 359	$ 556	$ (25)	$	$	$ 1,816
Less equity earnings	9	25	39				73
Segment operating income (loss)	$ 917	$ 334	$ 517	$ (25)	$	$	1,743
General corporate expenses							(84)
Total operating income							$ 1,659

Six months ended June 30, 2007							
Segment revenues:							
External	$ (76)	$ 771	$ 2,223	$ 2,270	$ 4	$	$ 5,192
Internal	1,098	15	22	412	9	(1,556)	
Total revenues	$ 1,022	$ 786	$ 2,245	$ 2,682	$ 13	$ (1,556)	$ 5,192
Segment profit (loss)	$ 397	$ 330	$ 405	$ (93)	$	$	$ 1,039
Less equity earnings	10	19	15				44
Segment operating income (loss)	$ 387	$ 311	$ 390	$ (93)	$	$	995
General corporate expenses							(76)
Total operating income							$ 919

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Notes (Continued)

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

	Total Assets	
	June 30, 2008	December 31, 2007
	(Millions)	
Exploration & Production (1)	$ 11,013	$ 8,692
Gas Pipeline	9,168	8,624
Midstream Gas & Liquids	7,228	6,604
Gas Marketing Services (2)	10,262	4,437
Other	3,699	3,592
Eliminations (3)	(10,224)	(7,073)
	31,146	24,876
Assets of discontinued operations	70	185
Total assets	$ 31,216	$ 25,061

(1) The increase in Exploration & Production s total assets is due primarily to an increase in derivative assets and an increase in property, plant and equipment net. The derivative asset increase is primarily due to the impact of changes in commodity prices on existing forward derivative contracts. Exploration & Production s derivative assets are more than offset by their derivative liabilities. The property, plant

and equipment net increase is primarily due to increased drilling activity.

(2) The increase in Gas Marketing Services 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. Gas Marketing Services derivative assets are substantially offset by their derivative liabilities.

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

Note 15. Recent Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 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 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). On January 1, 2008, we applied SFAS 157 to our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 for discussion of the adoption. Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. Application will be prospective when nonrecurring fair value measurements are required. We will assess the impact on our Consolidated Financial Statements of applying these requirements to nonrecurring fair value measurements for nonfinancial assets and nonfinancial liabilities.

In December 2007, the FASB issued SFAS No. 141(R) Business Combinations (SFAS 141(R)). SFAS 141(R) applies to all business combinations and establishes guidance for recognizing and measuring identifiable assets acquired, liabilities assumed, noncontrolling interests in the acquiree and goodwill. Most of these items are recognized at their full fair value on the acquisition date, including acquisitions where the acquirer obtains control but less than 100 percent ownership in the acquiree. SFAS 141(R) also requires expensing of restructuring and acquisition-related costs as incurred and establishes disclosure requirements to enable the evaluation of the nature and financial effects of the business combination. SFAS 141(R) is effective for business combinations with an acquisition date in fiscal years beginning after December 15, 2008. Also, beginning January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of goodwill. We are currently evaluating the changes provided in this Statement.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160). SFAS 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as

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Notes (Continued)
minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within stockholders equity as a separate component from the parent s equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS 160. SFAS 160 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. SFAS 160 is effective for fiscal years beginning after December 15, 2008, and early adoption is prohibited. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We will assess the impact on our Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, currently establishes the disclosure requirements for derivative instruments and hedging activities. SFAS 161 amends and expands the disclosure requirements of Statement 133 with enhanced quantitative, qualitative and credit risk disclosures. The Statement requires quantitative disclosure in a tabular format about the fair values of derivative instruments, gains and losses on derivative instruments and information about where these items are reported in the financial statements. Also required in the tabular presentation is a separation of hedging and nonhedging activities. Qualitative disclosures include outlining objectives and strategies for using derivative instruments in terms of underlying risk exposures, use of derivatives for risk management and other purposes and accounting designation, and an understanding of the volume and purpose of derivative activity. Credit risk disclosures provide information about credit risk related contingent features included in derivative agreements. SFAS 161 also amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to clarify that disclosures about concentrations of credit risk should include derivative instruments. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We plan to apply this Statement beginning in 2009. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We will assess the application of this Statement on our disclosures in our Consolidated Financial Statements.

On June 16, 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 requires that unvested share-based payment awards containing nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) be considered participating securities and included in the computation of earnings per share (EPS) pursuant to the two-class method of FASB Statement No. 128, Earnings per Share. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. All prior-period EPS data presented shall be adjusted retrospectively to conform to this FSP. Early application is not permitted. This FSP is not anticipated to have a material impact on our EPS attributable to the common stockholders.

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

Company Outlook

Our plan for 2008 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit;
- Invest in our 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;
  - Continue to invest in expansion projects on our interstate natural gas pipelines.

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;
- Decreased drilling success by third parties served by Midstream and Gas Pipeline;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements);
- General economic, financial markets, or industry downturn;
- Changes in the current political and regulatory environment.

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 six months ended June 30, 2008, increased $422 million compared to the six months ended June 30, 2007. This increase is reflective of:

- Higher net realized average prices and continued strong natural gas production growth at Exploration & Production;
- A pre-tax gain of $148 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production;
- Continued favorable commodity price margins at Midstream.

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the six months ended June 30, 2008, increased $782 million compared to the six months ended June 30, 2007, primarily due to our improved operating results. See additional discussion in Management s Discussion and Analysis of Financial Condition.

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Management s Discussion and Analysis (Continued)

Recent Events

In July 2008, we increased our position in the Fort Worth basin by agreeing to purchase undeveloped leasehold acreage and producing properties for $166 million. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation. The transaction is expected to close in September 2008.

In the first six months of 2008, we purchased ten million shares of our common stock for $365 million under our $1 billion common stock repurchase program at an average cost of $36.70 per share. (See Note 11 of Notes to Consolidated Financial Statements.) In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors. Our overall average cost per share under the completed repurchase program was $34.74.

In May 2008, we acquired certain undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin for $285 million. In July 2008, a third party exercised its contractual option to purchase, on the same terms and conditions, an interest in a portion of the acquired assets for $71 million.

In first-quarter 2008, we recognized pre-tax income of $128 million in *income from discontinued operations* related to our former Alaska operations. This amount includes $74 million related to cash received upon the favorable resolution of a matter involving pipeline transportation rates and $54 million related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank. In second-quarter 2008, we recorded a $54 million gain related to the favorable resolution of a matter involving pipeline transportation rates associated with our former Alaska operations. (See Note 3 of Notes to Consolidated Financial Statements.)

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. In the first quarter of 2008, we received $118 million in cash, with the remainder placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of $118 million in the first quarter of 2008 related to the initial cash received. In the second quarter of 2008, the remaining cash was received from escrow and recognized as income. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP. Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. is consolidated within our Gas Pipeline segment due to our control through the general partner.

During 2006, Transco filed a general rate case with the FERC for increases in rates. The new rates were effective, subject to refund, on March 1, 2007. On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco s pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement became effective June 1, 2008 and required refunds were issued in July 2008.

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 2007 Annual Report on Form 10-K.

Management s Discussion and Analysis (Continued)

Fair Value Measurements

On January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements (SFAS 157), for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 of Notes to Consolidated Financial Statements for disclosures regarding SFAS 157, including discussion of the fair value hierarchy levels and valuation methodologies.

Certain of our energy derivative assets and liabilities and other assets are valued using unobservable inputs and included in Level 3. At June 30, 2008, the fair value of the Level 3 assets represents 3 percent of the total assets measured at fair value. The fair value of the Level 3 liabilities represents approximately 11 percent of the total liabilities measured at fair value.

The instruments included in Level 3 at June 30, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. The remaining options are physically settled relating to the sale of natural gas. The options are valued using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant input, implied volatility by location, is unobservable. The impact of volatility on changes in the overall fair value of the options structured as collars is reduced because of the offsetting nature of the put and call positions. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices. The hedges are accounted for as cash flow hedges where net unrealized gains and losses from changes in fair value are recorded, to the extent effective, in *other comprehensive income* and subsequently impact earnings when the underlying hedged production is sold.

Exploration & Production has an unsecured credit agreement through December 2013 with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to options included in the facility.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2008, compared to the three and six months ended June 30, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended June 30,				Six months ended June 30,			
	2008	2007	$ Change from 2007*	% Change from 2007*	2008	2007	$ Change from 2007*	% Change from 2007*
	(Millions)				(Millions)			
Revenues	$ 3,729	$ 2,824	+905	+32%	$ 6,953	$ 5,192	+1,761	+34%
Costs and expenses:								
Costs and operating expenses	2,747	2,180	-567	-26%	5,120	4,023	-1,097	-27%
Selling, general and administrative expenses	131	108	-23	-21%	242	210	-32	-15%
Other income net	(35)	(18)	+17	+94%	(152)	(36)	+116	NM
General corporate expenses	42	36	-6	-17%	84	76	-8	-11%
Total costs and expenses	2,885	2,306			5,294	4,273		
Operating income	844	518			1,659	919		

Interest accrued net	(149)	(165)	+16	+10%	(306)	(332)	+26	+8%
Investing income	55	66	-11	-17%	110	118	-8	-7%
Minority interest in income of consolidated subsidiaries	(63)	(25)	-38	-152%	(102)	(39)	-63	-162%
Other income net		2	-2	-100%	5	4	+1	+25%
Income from continuing operations before income taxes	687	396			1,366	670		
Provision for income taxes	268	153	-115	-75%	531	257	-274	-107%
Income from continuing operations	419	243			835	413		
Income from discontinued operations	18	190	-172	-91%	102	154	-52	-34%
Net income	$ 437	$ 433			$ 937	$ 567		

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

Management s Discussion and Analysis (Continued)

Three months ended June 30, 2008 vs. three months ended June 30, 2007

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production due to both higher net realized average prices and increased production volumes sold. Additionally, Midstream experienced higher natural gas liquid (NGL) and crude oil marketing revenues, as well as higher olefin and NGL production revenues.

The increase in *cost and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and increased costs associated with our NGL and olefin production business at Midstream. Higher depreciation, depletion and amortization, and higher operating taxes at Exploration & Production also contributed to our increased expenses.

The increase in *selling, general and administrative (SG&A) expenses* includes the impact of higher staffing and compensation at our Exploration & Production and Midstream segments in support of increased activities.

Other income net within *operating income* in second-quarter 2008 includes a gain of $30 million recognized upon the receipt of the remaining proceeds related to the first-quarter 2008 sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production.

Other income net within *operating income* in second-quarter 2007 includes income of $17 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline.

The increase in *operating income* reflects both higher net realized average prices and continued strong natural gas production growth at Exploration and Production and continued favorable commodity price margins at Midstream. In addition, a gain of $30 million on the sale of a contractual right to a production payment at Exploration & Production contributed to the increase, as previously discussed.

Interest accrued net decreased primarily due to increased capitalized interest due to an increased level of capital expenditures. Additionally, lower interest rates on debt issuances that occurred late in the fourth quarter of 2007 and in the first half of 2008 contributed to a decrease in *interest accrued net*.

The decrease in *investing income* is due primarily to a $17 million decrease in interest income largely due to lower interest rates in the second quarter of 2008 compared to the second quarter of 2007 and an $8 million decrease in gains from the sales of cost-based investments. Partially offsetting these decreases is an increase in equity earnings of $14 million, primarily at Midstream.

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

Provision for income taxes increased primarily due to higher pre-tax income. The effective tax rates for the three months ended June 30, 2008 and 2007, are greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective rate for 2007 was partially offset by a benefit recognized based on a favorable private letter ruling received from the Internal Revenue Service (IRS) concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income from discontinued operations* for the three months ended June 30, 2008 and 2007.

Six months ended June 30, 2008 vs. six months ended June 30, 2007

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production due to both higher net realized average prices and increased production volumes sold. Additionally, Midstream experienced higher NGL and crude oil marketing revenues, as well as higher olefin and NGL production revenues.

The increase in *cost and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and increased costs associated with our olefin and NGL production business at Midstream. Higher depreciation, depletion and amortization, increased operating taxes and higher lease operating expenses at Exploration & Production also contributed to our increased expenses.

The increase in *SG&A expenses* includes the impact of higher staffing and compensation at our Exploration & Production and Midstream segments in support of increased activities.

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Management s Discussion and Analysis (Continued)

Other income net within *operating income* in 2008 includes a gain of $148 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production.

Other income net within *operating income* in 2007 includes income of $17 million associated with a change in estimate related to a regulatory liability at Northwest Pipeline.

The increase in *operating income* reflects both higher net realized average prices and continued strong natural gas production growth at Exploration & Production and continued favorable commodity price margins at Midstream. In addition, it also reflects a gain of $148 million on the sale of a contractual right to a production payment at Exploration & Production, as previously discussed.

Interest accrued net decreased primarily due to lower interest rates on debt issuances that occurred late in the fourth quarter of 2007 and in the first half of 2008 for which the proceeds were primarily used to retire existing debt bearing higher interest rates. While our overall debt balances have been relatively comparable, the net effect of these retirements and issuances has resulted in lower rates, including amounts refinanced under our $1.5 billion unsecured credit facility. (See Note 9 of Notes to Consolidated Financial Statements.) Additionally, increased capitalized interest due to an increased level of capital expenditures contributed to a decrease in *interest accrued net*.

The decrease in *investing income* is due primarily to a $30 million decrease in interest income largely due to lower average interest rates in 2008 compared to 2007 and a $5 million decrease in gains from the sales of cost-based investments. Partially offsetting these decreases is an increase in equity earnings of $29 million, primarily at Midstream.

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

Provision for income taxes increased primarily due to higher pre-tax income. The effective tax rates for the six months ended June 30, 2008 and 2007, are greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations. The higher effective rate for 2007 was partially offset by a benefit recognized based on a favorable private letter ruling received from the IRS concerning our securities litigation settlement and fees, a portion of which were previously treated as nondeductible.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income from discontinued operations* for the six months ended June 30, 2008 and 2007.

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Six Months Ended June 30, 2008

During the first six months of 2008, we continued our development drilling program in our growth basins. Accordingly, we:

- Benefited from increased domestic net realized average prices, which increased by approximately 37 percent compared to the first six months of 2007. The domestic net realized average price for the first six months of 2008 was $7.35 per thousand cubic feet of gas equivalent (Mcfe) compared to $5.36 per Mcfe in 2007. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

- Increased average daily domestic production levels by approximately 22 percent compared to the first six months of 2007. The average daily domestic production for the first six months of 2008 was approximately 1,061 million cubic feet of gas equivalent (MMcfe) compared to 872 MMcfe in 2007. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

- Increased capital expenditures for domestic drilling, development, and acquisition activity in the first six months of 2008 by $368 million compared to 2007. Capital expenditures for 2008 include an acquisition in the Piceance basin discussed in *Significant events* below.

The benefits of higher net realized average prices and higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and lease service costs. In addition, higher production volumes increased depletion, depreciation, and amortization expense.

Significant events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for $148 million. In the first quarter of 2008, we received $118 million in cash, with the remainder placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of $118 million in the first quarter of 2008 related to the initial cash received. In the second quarter of 2008, the remaining cash was received from escrow and recognized as income. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In May 2008, we acquired certain undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin for $285 million. In July 2008, a third party exercised its contractual option to purchase, on the same terms and conditions, an interest in a portion of the acquired assets for $71 million.

In July 2008, we increased our position in the Fort Worth basin by agreeing to purchase undeveloped leasehold acreage and producing properties for $166 million. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties in the Barnett Shale formation. The transaction is expected to close in September 2008.

Outlook for the Remainder of 2008

Our expectations for the remainder of the year include:

- Maintaining our development drilling program in the Piceance, Powder River, San Juan, Fort Worth and Arkoma basins through our remaining planned capital expenditures projected between $900 million and $1.1 billion.

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Management s Discussion and Analysis (Continued)

Continuing to grow our average daily domestic production level with a goal of 10 to 20 percent growth compared to 2007.

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 using NYMEX and basis fixed-price contracts and collar agreements.

NYMEX and basis fixed-price contracts We have the following contracts for our daily domestic production, shown at weighted-average volumes measured at million cubic feet per day (MMcf/d) and basin-level weighted-average prices measured at dollars per thousand cubic feet ($/Mcf):

	Volume (MMcf/d)	**% of Daily Domestic Production**	**Price ($/Mcf)**
Remaining 2008	70		$3.98
2nd Quarter 2008	70	6%	$4.00
2nd Quarter 2007	172	19%	$3.77
Year-to-date 2008	70	7%	$3.96
Year-to-date 2007	172	20%	$3.85

Collar agreements In addition, we have the following collar agreements for our daily domestic production, shown at weighted-average volumes and basin-level weighted-average prices:

	NYMEX		**Rockies**		**San Juan**		**Mid-Continent**	
	Volume (MMcf/d)	**Floor - Ceiling Price ($/Mcf)**	**Volume (MMcf/d)**	**Floor - Ceiling Price ($/Mcf)**	**Volume (MMcf/d)**	**Floor - Ceiling Price ($/Mcf)**	**Volume (MMcf/d)**	**Floor - Ceiling Price ($/Mcf)**
Remaining 2008			160	$ 6.08 - $9.04	220	$ 6.37 - $9.00	80	$ 7.02 - $9.77
2nd Quarter 2008			160	$ 6.08 - $9.04	220	$ 6.37 - $9.00	80	$ 7.02 - $9.77
2nd Quarter 2007	15	$ 6.50 - $8.25	50	$ 5.65 - $7.45	130	$ 5.98 - $9.63	75	$ 6.82 - $10.80
Year-to-date 2008			180	$ 6.22 - $9.24	184	$ 6.33 - $8.91	45	$ 7.03 - $9.65
Year-to-date 2007	15	$ 6.50 - $8.25	50	$ 5.65 - $7.45	130	$ 5.98 - $9.63	75	$ 6.82 - $10.80

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions and domestic natural gas production and consumption. Also, achievement of expectations can be affected by costs of services associated with drilling.

In addition, changes in laws and regulations may impact our development drilling program. The Colorado Oil & Gas Conservation Commission has proposed rules that could increase our costs of permitting and environmental compliance, may affect our ability to meet our anticipated drilling schedule and therefore may have an unfavorable effect on our future results of operations.

Period-Over-Period Results

	Three months ended June 30,		**Six months ended June 30,**	
	2008	**2007**	**2008**	**2007**
	(Millions)		**(Millions)**	
Segment revenues	$ 976	$ 539	$ 1,724	$ 1,022
Segment profit	$ 496	$ 209	$ 926	$ 397

Three months ended June 30, 2008 vs. three months ended June 30, 2007

Total *segment revenues* increased $437 million, or 81 percent, primarily due to the following:

$377 million, or 84 percent, increase in domestic production revenues reflecting $272 million associated with a 49 percent increase in net realized average prices and $105 million associated with a 24 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the effect of fewer volumes hedged by fixed-price contracts that are lower than the current market prices (see previous discussion of hedging). The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in

Management s Discussion and Analysis (Continued)

2008 and 2007 include approximately $26 million and $12 million, respectively, related to natural gas liquids and approximately $22 million and $10 million, respectively, related to condensate;

$66 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar increase in *segment costs and expenses*. This increase is primarily due to increases in natural gas prices and volumes sold.

These increases are partially offset by a $9 million increase in unrealized losses from hedge ineffectiveness. In 2008, there were $14 million in net unrealized losses from hedge ineffectiveness as compared to $5 million in net unrealized losses in 2007.

Total *segment costs and expenses* increased $151 million, primarily due to the following:

$66 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*;

$51 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$34 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

$12 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well and lease service expenses and facility expenses;

$12 million higher SG&A expenses primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. The higher SG&A expenses also include an increase of $5 million in bad debt expense.

These increases are partially offset by the $30 million gain associated with the previously discussed sale of our Peru interests in 2008.

The $287 million increase in s*egment profit* is primarily due to the 49 percent increase in domestic net realized average prices, the 24 percent increase in domestic production volumes sold, and the $30 million gain associated with the sale of our Peru interests, partially offset by the increases in *segment costs and expenses*.

Six months ended June 30, 2008 vs. six months ended June 30, 2007

Total *segment revenues* increased $702 million, or 69 percent, primarily due to the following:

$581 million, or 67 percent, increase in domestic production revenues reflecting $388 million associated with a 37 percent increase in net realized average prices and $193 million associated with a 22 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the effect of fewer volumes hedged by fixed-price contracts that are lower than the current market prices (see previous discussion of hedging). The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in 2008 and 2007 include approximately $43 million and $19 million, respectively, related to natural gas liquids and approximately $36 million and $16 million, respectively, related to condensate;

$115 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties, which is offset by a similar increase in *segment costs and expenses*. This increase is primarily due to increases in natural gas prices and volumes sold.

These increases are partially offset by a $9 million increase in unrealized losses from hedge ineffectiveness. In 2008, there were $16 million in net unrealized losses from hedge ineffectiveness as compared to $7 million in net unrealized losses in 2007.

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Management s Discussion and Analysis (Continued)

Total *segment costs and expenses* increased $172 million, primarily due to the following:

- $115 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*;

- $103 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

- $49 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

- $28 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well and lease service expenses and facility expenses;

- $13 million higher SG&A expenses primarily due to increased staffing in support of increased drilling and operational activity, including higher compensation. The higher SG&A expenses also include an increase of $5 million in bad debt expense.

These increases are partially offset by the $148 million gain associated with the previously discussed sale of our Peru interests in 2008.

The $529 million increase in s*egment profit* is primarily due to the 37 percent increase in domestic net realized average prices, the 22 percent increase in domestic production volumes sold, and the $148 million gain associated with the sale of our Peru interests, partially offset by the increases in *segment costs and expenses*.

Gas Pipeline

Overview of Six Months Ended June 30, 2008

Gas Pipeline master limited partnership

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP. Upon completion of these transactions, we now own approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. is consolidated within our Gas Pipeline segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.) Gas Pipeline s segment profit includes 100 percent of Williams Pipeline Partners L.P. s segment profit, with the minority interest s share presented below segment profit.

Status of rate case

During 2006, Transco filed a general rate case with the FERC for increases in rates. The new rates were effective, subject to refund, on March 1, 2007. On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in their pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement became effective June 1, 2008 and required refunds were issued in July 2008.

Outlook for the Remainder of 2008

Gulfstream expansion projects

In June 2007, our equity method investee, Gulfstream Natural Gas System, L.L.C. (Gulfstream), received FERC approval to extend its existing pipeline approximately 34 miles within Florida. The extension will fully subscribe the remaining 345 thousand dekatherms per day (Mdt/d) of firm capacity on the existing pipeline. Construction began in January 2008 and it is expected to be placed into service in August 2008. Gulfstream s estimated cost of this project is approximately $127 million.

Management s Discussion and Analysis (Continued)

In September 2007, Gulfstream received FERC approval to construct 17.5 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion is expected to be placed into service in October 2008, and the compressor facility is expected to be placed into service in January 2009. The expansion will increase capacity by 155 Mdt/d. Gulfstream s estimated cost of this project is approximately $160 million.

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. Our estimated cost of the project is approximately $169 million. The expansion will increase capacity by 142 Mdt/d and is expected to be placed into service in two phases, occurring in November 2008 and November 2009.

Period-Over-Period Results

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Segment revenues	$ 406	$ 415	$ 819	$ 786
Segment profit	$ 179	$ 180	$ 359	$ 330

Three months ended June 30, 2008 vs. three months ended June 30, 2007

Segment revenues decreased $9 million, or 2 percent, due primarily to a $24 million decrease in revenues associated with the absence of a 2007 sale of excess inventory gas (offset in *costs and operating expenses)*, partially offset by a $13 million increase in transportation revenue largely as a result of expansion projects that Transco placed into service in fourth-quarter 2007.

Costs and operating expenses decreased $17 million, or 8 percent, due primarily to a $24 million decrease associated with the absence of a 2007 sale of excess inventory gas (offset in *segment revenues*).

Other income net changed unfavorably by $12 million due primarily to the absence in 2008 of $17 million of income recorded in the second quarter of 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline. Partially offsetting this unfavorable change was a $9 million gain on the sale of excess inventory gas recognized in second-quarter 2008 upon FERC approval.

The $1 million, or 1 percent, decrease in *segment profit* is due primarily to the absence in 2008 of the $17 million change in estimate discussed above, substantially offset by additional revenues resulting from expansions placed into service in fourth-quarter 2007 and a $9 million second-quarter 2008 gain from the sale of excess inventory gas.

Six months ended June 30, 2008 vs. six months ended June 30, 2007

Segment revenues increased $33 million, or 4 percent, due primarily to a $49 million increase in transportation revenues resulting primarily from Transco s new rates, which were effective March 2007, and expansion projects that Transco placed into service in fourth-quarter 2007. In addition, *segment revenues* increased $10 million due to transportation imbalance settlements (offset in *costs and operating expenses*). Partially offsetting these increases is a $24 million decrease associated with the absence of a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses decreased $11 million, or 3 percent, due primarily to a $24 million decrease associated with the absence of a 2007 sale of excess inventory gas (offset in *segment revenues)* partially offset by an increase in costs of $10 million associated with transportation imbalance settlements (offset in *segment revenues*).

Other income net changed unfavorably by $18 million due primarily to the absence in 2008 of $17 million of income as previously discussed and $9 million of higher costs associated with project development. Partially offsetting these unfavorable changes is a $9 million gain on the sale of excess inventory gas recognized in second-quarter 2008.

Management s Discussion and Analysis (Continued)

The $29 million, or 9 percent, increase in *segment profit* is due primarily to $33 million of higher *segment revenues*, primarily reflecting Transco s new transportation rates and new expansion projects placed into service in fourth-quarter 2007, and a $9 million gain on the sale of excess inventory gas, partially offset by the absence in 2008 of $17 million of income related to a change in estimate related to a regulatory liability at Northwest Pipeline.

Midstream Gas & Liquids

Overview of Six Months Ended June 30, 2008

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 2008 include the following:

Continued favorable commodity price margins

High crude prices, which generally correlate to strong NGL prices in relationship to natural gas prices, have contributed significantly to our realized unit margins. The geographic diversification of Midstream assets also contributed to realized unit margins that were generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. Our average realized NGL per unit margin at our processing plants during the second quarter of 2008 was 51 cents per gallon (cpg), a 9 percent increase over the same period in 2007. Our average realized NGL per unit margin for the six months ended June 30, 2008, was 57 cpg, a 52 percent increase over the same period in 2007. The deterioration from the first quarter 2008 per unit margin of 64 cpg and from a record high 83 cpg in the fourth quarter of 2007 is due primarily to rising prices for natural gas in the West region. NGL margins have exceeded our rolling five-year average for the last five quarters, in spite of strong NGL margins over the last year significantly increasing our rolling five-year average from approximately 20 cpg at the end of the second quarter of 2007 to 30 cpg at the end of the second quarter of 2008. References to our NGL prices and margins include the impact of our hedging activities, which are discussed in *Outlook for the Remainder of 2008*.

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Management s Discussion and Analysis (Continued)

Major 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.

Gulf Coast region

In the deepwater of the Gulf of Mexico, we continue construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon in the eastern deepwater of the Gulf of Mexico. We expect this project to begin contributing to our segment profit in the latter part of 2008. In addition, we continue construction activities on the Perdido Norte project which will include an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. We expect this project to begin contributing to our segment profit at the end of 2009. The estimated cost of our Gulf Coast region major expansion projects is approximately $810 million, approximately $245 million of which we expect to spend during 2008.

West region

Our major expansion project currently in construction in the West region is the new Willow Creek facility, a 450 MMcf/d natural gas processing plant in western Colorado s Piceance basin. Major equipment purchases, vessel fabrication and site clearing and grading are well under way. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the latter part of 2009. In May 2008, we announced that we plan to significantly increase the processing and NGL production capacities at our Echo Springs natural gas processing plant in Wyoming. The addition of a fourth cryogenic processing train will add approximately 350 MMcf/d of processing capacity and 30,000 barrels per day of NGL production capacity, roughly doubling Echo Spring s volumes in both cases. We expect to begin construction on the fourth train at Echo Springs during the second half of 2009 and to bring the additional capacity online during late 2010, subject to all applicable permitting. We expect to spend approximately $570 million on these expansion projects in the West, including approximately $275 million during 2008.

Williams Partners L.P.

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with EITF Issue No. 04-5, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 2 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit, with the minority interest s share presented below segment profit. The debt and equity issued by Williams Partners L.P. to third parties is reported as a component of our consolidated debt balance and minority interest balance, respectively.

Outlook for the Remainder of 2008

The following factors could impact our business in 2008.

- 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. NGL products are the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene or plastics, due to the relative price of alternative crude-based feedstocks. Although forecasted domestic demand for polyethylene has weakened, the global markets remain robust. Due to strong drilling and lower demand, natural gas prices in the Rocky Mountain areas have not increased proportionally to natural gas price increases at the industry benchmark Henry Hub area. These global market conditions, aided by the weak U.S. dollar and the differential in gas prices in the Rocky Mountain areas, currently support NGL margins continuing to exceed our rolling five-year average.

We have agreed to dedicate our equity NGL volumes from our two Wyoming plants for transport under a long-term shipping agreement with Overland Pass Pipeline Company, LLC. We currently have a 1 percent interest in Overland Pass Pipeline Company, LLC and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational, which is expected to occur later in 2008. The costs of our current shipping arrangement will continue to be higher than the arrangements we utilized in 2007 until the Overland Pass pipeline is completed. When the pipeline is complete, the terms of our transportation agreement represent significant savings compared to 2007.

As part of our efforts to manage commodity price risks on an enterprise basis, during December 2007, and January and February 2008, we entered into various financial contracts. Approximately 25 percent of our forecasted domestic NGL sales for the last six months of 2008 are hedged with collar agreements or fixed-price swap contracts. Approximately 21 percent of our forecasted domestic NGL sales for the last six months of 2008 have been hedged with collar agreements at an expected weighted average sales price that approximates our average 2007 domestic NGL sales price and approximately 4 percent of our forecasted domestic NGL sales for the last six months of 2008 have been hedged with fixed-price swap contracts. The natural gas shrink requirements associated with the sales under the fixed-price swap contracts have also been hedged through Gas Marketing Services with physical gas purchase contracts, thus effectively hedging the margin on the volumes associated with fixed-price swap contracts at a level approximating our 2007 average per unit margins.

We are currently experiencing restrictions on the volume of NGLs we can deliver to third-party pipelines in our West region. These restrictions are caused by a lack of third-party pipeline transportation capacity and impact our ability to recover and sell NGLs, primarily ethane. While limited alternate delivery options are available, NGLs delivered under these alternatives will likely realize lower pricing than NGLs being delivered into the traditional third-party markets. These restrictions are expected to continue until we and other processors are able to deliver NGLs to the Overland Pass Pipeline, which we expect will occur in the late third or early fourth quarter of this year. Transition to the Overland Pass Pipeline is expected to result in lower transportation costs in the West.

Margins in our olefins business are highly dependent upon continued economic growth within the global economy. A significant slow down in the economy in the United States could reduce the demand for the petrochemical products we produce in both Canada and the United States. However, based on the previously mentioned global demand and our increased ownership interest in the Geismar olefins facility effective July 2007, we anticipate results from our olefins business to be above 2007 levels.

We expect fee revenues in our Gulf Coast region to be slightly above 2007 levels as we expand our Devils Tower infrastructure to serve the Blind Faith and Bass Lite prospects and increase the per unit rate of revenue recognition for resident production at our Devils Tower facility. While we expect to continue to connect new supplies in the deepwater, this increase is expected to be partially offset by lower volumes in other deepwater areas due to natural declines. Fee revenues include gathering, processing, production handling and transportation fees.

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. As we pursue these activities, our operating and general and administrative expenses are expected to increase.

Our right-of-way agreement with the Jicarilla Apache Nation (JAN), which covered certain gathering system assets in Rio Arriba County of northern New Mexico, expired on December 31, 2006. We currently operate our gathering assets on the JAN lands pursuant to a special business license granted by the JAN which expires August 31, 2008, and are negotiating with the JAN to sell them these gathering assets. Although the special business license required the execution of a purchase and sale agreement for these gathering assets on or before May 31, 2008, we continue to operate the gathering assets under the terms of the special business license and it is our expectation that we will continue to operate these assets past the completion date of negotiations with the JAN. It is anticipated that if this sale occurs, it will be completed during the fourth quarter of 2008 or first quarter of 2009. Current expectations are that the final terms of the sale will allow us to maintain partial revenues associated with gathering and processing services for gas produced from the

Management s Discussion and Analysis (Continued)

JAN lands and continued operation of the gathering assets on the JAN lands through at least 2009. We believe the expected proceeds from the sale of these assets will substantially exceed their carrying value. Based on current estimated gathering volumes and the range of annual average commodity prices over the past five years, we estimate that gas produced on or isolated by the JAN lands represents approximately $20 million to $30 million of the West region s annual gathering and processing revenue less related product costs.

Period-Over-Period Results

	Three months ended June 30,		Six months ended June 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Segment revenues	$ 1,754	$ 1,243	$ 3,311	$ 2,245
Segment profit (loss)				
Domestic gathering & processing	232	212	436	335
Venezuela	28	29	54	56
Other	61	29	116	54
Indirect general and administrative expense	(26)	(19)	(50)	(40)
Total	$ 295	$ 251	$ 556	$ 405

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 June 30, 2008 vs. three months ended June 30, 2007

The $511 million, or 41 percent, increase in *segment revenues* is largely due to:

A $169 million increase in revenues from the marketing of NGLs and crude oil due primarily to higher NGL and crude prices, partially offset by a decrease in olefin marketing volumes sold. These changes are offset by similar changes in marketing purchases.

A $159 million increase in revenues in our olefins production business due primarily to higher prices and higher volumes associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.

A $155 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices.

Segment costs and expenses increased $475 million, or 48 percent, primarily as a result of:

A $167 million increase in NGL and crude marketing purchases, partially offset by a decrease in olefin marketing purchases. These changes are offset by similar changes in marketing revenues.

A $137 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices.

A $133 million increase in costs in our olefins production business.

A $27 million increase in operating expenses including higher operations and maintenance expenses and transportation expenses in the eastern Gulf of Mexico.

The $44 million, or 18 percent, increase in Midstream s *segment profit* reflects $26 million higher margins in our olefins production business and $18 million higher NGL margins, as well as the other previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Management s Discussion and Analysis (Continued)

Domestic gathering & processing

The $20 million increase in *domestic gathering & processing segment profit* includes a $4 million increase in the West region and a $16 million increase in the Gulf Coast region.

The $16 million increase in the Gulf Coast region s *segment profit* is primarily due to higher NGL margins and higher fee revenues, partially offset by higher operating costs. The significant components of this increase include the following:

- NGL margins increased $23 million driven by significantly higher NGL prices, partially offset by a significant increase in costs associated with the production of NGLs.

- Fee revenues from our deepwater assets increased $6 million due primarily to higher volumes as we connect new supplies in the deepwater.

- Operating expenses increased $7 million due primarily to higher maintenance costs and transportation expenses in the eastern Gulf of Mexico.

Other

The significant components of the $32 million increase in *segment profit* of our other operations include the following:

- $26 million in higher margins in our olefins production business due primarily to higher product prices and higher volumes associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.

- Higher equity earnings including $4 million higher Discovery Producer Services, L.L.C. equity earnings and $4 million higher Aux Sable Liquids Products, L.P. equity earnings due primarily to favorable processing margins.

- $7 million lower foreign exchange losses related to the revaluation of current assets held in U.S. dollars within our Canadian operations.

These increases are partially offset by $10 million higher operations and maintenance expenses due primarily to the increase in ownership of the Geismar olefins facility effective July 2007.

Six months ended June 30, 2008 vs. six months ended June 30, 2007

The $1,066 million, or 47 percent, increase in *segment revenues* is largely due to:

- A $399 million increase in revenues from the marketing of NGLs and crude oil due primarily to higher NGL and crude prices, partially offset by a decrease in olefin marketing volumes sold. These changes are offset by similar changes in marketing purchases.

- A $353 million increase in revenues in our olefins production business due primarily to higher prices of NGL products produced in our Canadian olefins operations and higher volumes associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.

- A $278 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices.

Management s Discussion and Analysis (Continued)

Segment costs and expenses increased $939 million, or 51 percent, primarily as a result of:

- A $402 million increase in NGL and crude marketing purchases, partially offset by a decrease in olefin marketing purchases. These changes are offset by similar changes in marketing revenues.
- A $298 million increase in costs in our olefins production business.
- A $158 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices.
- A $53 million increase in operating expenses including higher operations and maintenance expenses and transportation expenses in the eastern Gulf of Mexico.

The $151 million, or 37 percent, increase in Midstream s *segment profit* reflects $120 million higher NGL margins and $55 million higher margins in our olefins production business, as well as the other previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The $101 million increase in *domestic gathering & processing segment profit* includes a $54 million increase in the West region and a $47 million increase in the Gulf Coast region.

The $54 million increase in our West region s *segment profit* primarily results from higher NGL marg