WILLIAMS COMPANIES INC
Form 10-Q
November 06, 2008

Table of Contents

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

(Mark One)

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

For the quarterly period ended September 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	Smaller reporting company o
		(Do not check if a smaller reporting company)	

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 October 31, 2008**

Common Stock, $1 par value	578,674,347	Shares

The Williams Companies, Inc.
Index

Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

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

Amounts and nature of future capital expenditures;

Expansion and growth of our business and operations;

Financial condition and liquidity;

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.

Table of Contents

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or 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, future changes in our credit ratings and the availability and cost of credit;
- Risks associated with future weather conditions;
- Our ability to successfully manage the risks associated with selling and marketing products in the wholesale energy markets;
- Acts of terrorism;
- Additional risks described in our filings with the Securities and Exchange Commission.

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 or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

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

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. 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.

Table of Contents

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

(Dollars in millions, except per-share amounts)	**Three months ended September 30, 2008**	**2007**	**Nine months ended September 30, 2008**	**2007**
Revenues:				
Exploration & Production	$ 883	$ 499	$ 2,607	$ 1,521
Gas Pipeline	407	392	1,226	1,178
Midstream Gas & Liquids	1,436	1,360	4,747	3,605
Gas Marketing Services	1,716	1,247	5,376	3,929
Other	6	7	18	20
Intercompany eliminations	(1,181)	(645)	(3,754)	(2,201)
Total revenues	3,267	2,860	10,220	8,052
Segment costs and expenses:				
Costs and operating expenses	2,386	2,222	7,506	6,245
Selling, general and administrative expenses	133	107	375	317
Other income net		(2)	(152)	(38)
Total segment costs and expenses	2,519	2,327	7,729	6,524
General corporate expenses	34	40	118	116
Operating income (loss):				
Exploration & Production	356	159	1,273	546
Gas Pipeline	152	162	486	473
Midstream Gas & Liquids	226	279	743	669
Gas Marketing Services	16	(67)	(9)	(160)
Other	(2)		(2)	
General corporate expenses	(34)	(40)	(118)	(116)
Total operating income	714	493	2,373	1,412
Interest accrued	(166)	(171)	(496)	(515)
Interest capitalized	16	9	40	21
Investing income	65	78	175	196
Minority interest in income of consolidated subsidiaries	(55)	(29)	(157)	(68)
Other income net	2	8	7	12
Income from continuing operations before income taxes	576	388	1,942	1,058
Provision for income taxes	207	160	738	417

Income from continuing operations	369	228	1,204	641
Income (loss) from discontinued operations	(3)	(30)	99	124
Net income	$ 366	$ 198	$ 1,303	$ 765
Basic earnings per common share:				
Income from continuing operations	$ .63	$ .38	$ 2.07	$ 1.07
Income (loss) from discontinued operations		(.05)	.17	.21
Net income	$ .63	$ .33	$ 2.24	$ 1.28
Weighted-average shares (thousands)	577,448	596,836	582,105	598,124
Diluted earnings per common share:				
Income from continuing operations	$ .62	$ .38	$ 2.02	$ 1.05
Income (loss) from discontinued operations		(.05)	.17	.20
Net income	$ .62	$ .33	$ 2.19	$ 1.25
Weighted-average shares (thousands)	589,138	610,651	594,630	611,761
Cash dividends declared per common share	$ .11	$ .10	$ .32	$ .29

See accompanying notes.

3

Table of Contents

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

(Dollars in millions, except per-share amounts)	September 30, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,524	$ 1,699
Accounts and notes receivable (net of allowance of $38 at September 30, 2008 and $27 at December 31, 2007)	1,089	1,192
Inventories	324	209
Derivative assets	2,091	1,736
Assets of discontinued operations	16	185
Deferred income taxes	72	199
Other current assets and deferred charges	365	318
Total current assets	5,481	5,538
Investments	990	901
Property, plant and equipment, at cost	25,335	22,787
Less accumulated depreciation, depletion, and amortization	(7,686)	(6,806)
Property, plant and equipment net	17,649	15,981
Derivative assets	1,008	859
Goodwill	1,011	1,011
Other assets and deferred charges	754	771
Total assets	$ 26,893	$ 25,061
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,072	$ 1,131
Accrued liabilities	1,144	1,158
Derivative liabilities	1,968	1,824
Liabilities of discontinued operations	13	175
Long-term debt due within one year	84	143
Total current liabilities	4,281	4,431
Long-term debt	7,827	7,757
Deferred income taxes	3,525	2,996
Derivative liabilities	1,002	1,139
Other liabilities and deferred income	1,045	933
Contingent liabilities and commitments (Note 12)		

Minority interests in consolidated subsidiaries		639		1,430
Stockholders equity:				
Common stock (960 million shares authorized at $1 par value; 613 million shares issued at September 30, 2008 and 608 million shares issued at December 31, 2007)		613		608
Capital in excess of par value		8,077		6,748
Retained earnings (deficit)		823		(293)
Accumulated other comprehensive income (loss)		102		(121)
		9,615		6,942
Less treasury stock, at cost (35 million shares of common stock at September 30, 2008 and 22 million shares at December 31, 2007)		(1,041)		(567)
Total stockholders equity		8,574		6,375
Total liabilities and stockholders equity	$	26,893	$	25,061

See accompanying notes.

Table of Contents

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

(Dollars in millions)	Nine months ended September 30, 2008	2007
OPERATING ACTIVITIES:		
Net income	$ 1,303	$ 765
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	953	792
Provision for deferred income taxes	497	445
Provision for loss on investments, property and other assets	19	136
Net gain on disposition of assets	(37)	(20)
Gain on sale of contractual production rights	(148)	
Minority interest in income of consolidated subsidiaries	157	68
Amortization of stock-based awards	33	58
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	278	(72)
Inventories	(111)	23
Margin deposits and customer margin deposits payable	72	31
Other current assets and deferred charges	(78)	(11)
Accounts payable	(252)	(2)
Accrued liabilities	17	(250)
Changes in current and noncurrent derivative assets and liabilities	(103)	200
Other, including changes in noncurrent assets and liabilities	6	(57)
Net cash provided by operating activities	2,606	1,677
FINANCING ACTIVITIES:		
Proceeds from long-term debt	674	184
Payments of long-term debt	(634)	(318)
Proceeds from issuance of common stock	32	37
Proceeds from sale of limited partner units of consolidated partnerships	362	
Tax benefit of stock-based awards	21	21
Dividends paid	(186)	(174)
Purchase of treasury stock	(474)	(234)
Dividends and distributions paid to minority interests	(90)	(57)
Changes in restricted cash	(20)	(4)
Changes in cash overdrafts	4	43
Other net	(5)	(6)
Net cash used by financing activities	(316)	(508)
INVESTING ACTIVITIES:		
Property, plant and equipment:		

Capital expenditures	(2,593)	(2,100)
Net proceeds from dispositions	37	1
Changes in accounts payable and accrued liabilities	2	34
Proceeds from sale of discontinued operations	22	
Purchases of investments/advances to affiliates	(105)	(37)
Purchases of auction rate securities		(304)
Proceeds from sales of auction rate securities		353
Proceeds from sale of contractual production rights	148	
Proceeds from dispositions of investments and other assets	25	65
Other net	(1)	5
Net cash used by investing activities	(2,465)	(1,983)
Decrease in cash and cash equivalents	(175)	(814)
Cash and cash equivalents at beginning of period	1,699	2,269
Cash and cash equivalents at end of period	$ 1,524	$ 1,455

See accompanying notes.

5

Table of Contents

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

Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2008, and results of operations for the three and nine months ended September 30, 2008 and 2007 and cash flows for the nine months ended September 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.

Recent Market Events

The recent instability in financial markets has created global concerns about the liquidity of financial institutions and is having overarching impacts on the economy as a whole. In this volatile economic environment, many financial markets, institutions and other businesses remain under considerable stress. In addition, oil and gas prices have recently experienced significant declines. These events are impacting our business. However, we note the following:

- We are reducing our levels of expected capital expenditures.

- As of September 30, 2008, we have approximately $1.5 billion of cash and cash equivalents and nearly $2.6 billion of available capacity under our credit facilities.

- We have no significant debt maturities until 2011.

- Our risk from our net credit exposure to derivative counterparties, considering master netting agreements and collateral support, is not significant. Our net credit exposure as of September 30, 2008, related to derivative assets is $384 million, net of $54 million of collateral support. This exposure is concentrated with investment grade financial institution counterparties.

To the extent that these recent events drive sustained lower energy commodity prices, it will negatively impact our future results of operations and cash flow from operations and could result in a further reduction in capital expenditures. These impacts could also include the future nonperformance of counterparties or impairments of goodwill and long-lived assets.

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 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.

Table of Contents

Notes (Continued)

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, we consolidate Williams Partners L.P. 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, we consolidate Williams Pipeline Partners L.P. within our Gas Pipeline segment due to our control through the general partner.

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 nine months ended September 30, 2008 and 2007.

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)		(Millions)	
Revenues	$	$ 703	$ 5	$ 2,210
Income (loss) from discontinued operations before income taxes	(4)	(52)	159	324
(Impairments) and gain (loss) on sales	8	2	8	(124)
(Provision) benefit for income taxes	(7)	20	(68)	(76)
Income (loss) from discontinued operations	$ (3)	$ (30)	$ 99	$ 124

Income (loss) from discontinued operations before income taxes for the nine months ended September 30, 2008, includes $128 million of gains from the favorable resolution of matters involving pipeline transportation rates associated with our former Alaska operations and $54 million of income from a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank (see Note 12). These gains are partially offset by a $10 million charge from a settlement primarily related to the sale of natural gas liquids pipeline systems in 2002 (see Note 12) and a charge of $10 million associated with an oil purchase contract related to our former Alaska refinery.

Income (loss) from discontinued operations before income taxes for the nine months ended September 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 three and nine months ended September 30, 2007, includes unrealized mark-to-market losses of $49 million and $72 million, respectively.

(Impairments) and gain (loss) on sales for the three and nine months ended September 30, 2008, primarily represents $9 million of final proceeds from the sale of our former power business.

(*Impairments) and gain (loss) on sales* for the nine months ended September 30, 2007, includes impairments of $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 $13 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.

Table of Contents

Notes (Continued)

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of September 30, 2008 and December 31, 2007. The September 30, 2008, and December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to the purchaser of our former power business, entirely offset by reciprocal positions with that same party. 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.

	September 30, 2008	December 31, 2007
	(Millions)	
Derivative assets	$ 11	$ 114
Accounts receivable net	5	55
Other current assets		3
Total current assets	16	172
Property, plant and equipment net		8
Other noncurrent assets		5
Total noncurrent assets		13
Total assets	$ 16	$ 185
Derivative liabilities	$ 11	$ 114
Other current liabilities	2	61
Total current liabilities	13	175
Total liabilities	$ 13	$ 175

Note 4. Asset Sales, Impairments and Other Accruals

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

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Exploration & Production				
Gain on sale of contractual right to an international production payment	$	$	$ (148)	$
Impairment of certain natural gas producing properties	14		14	
Gas Pipeline				
				(17)

Income from change in estimate related to a regulatory liability				
Income from payments received for a terminated firm transportation agreement on Grays Harbor lateral. Associated with this gain is interest income of $2 million, which is included in *investing income*		(12)		(18)
Gain on sale of certain south Texas assets	(10)		(10)	

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 $10 million and $15 million for the nine months ended September 30, 2008 and 2007, respectively.

Table of Contents

Notes (Continued)

Note 5. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Current:				
Federal	$ 33	$ 8	$ 299	$ 5
State	(11)	6	34	7
Foreign	10	12	39	37
	32	26	372	49
Deferred:				
Federal	149	118	312	319
State	22	11	41	33
Foreign	4	5	13	16
	175	134	366	368
Total provision	$ 207	$ 160	$ 738	$ 417

The effective income tax rates for the three and nine months ended September 30, 2008, are greater than the federal statutory rate due primarily to the effect of state income taxes.

The effective income tax rates for the three and nine months ended September 30, 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 nine months ended September 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 September 30,		Nine months ended September 30,	
	2008	2007	2008	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 common share (1)	$ 369	$ 228	$ 1,204	$ 641
Basic weighted-average shares (2)	577,448	596,836	582,105	598,124
Effect of dilutive securities:				
Nonvested restricted stock units	1,304	1,769	1,337	1,553

Stock options	3,468	4,726	4,003	4,762
Convertible debentures (3)	6,918	7,320	7,185	7,322
Diluted weighted-average shares	589,138	610,651	594,630	611,761
Earnings per common share from continuing operations:				
Basic	$ .63	$ .38	$ 2.07	$ 1.07
Diluted	$ .62	$ .38	$ 2.02	$ 1.05

(1) The three and nine month periods for both years include $1 million and $2 million, respectively, of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) Since third-quarter 2007, we have purchased 29 million shares of our common stock under a stock repurchase program (see Note 11).

(3) During third-quarter 2008, we converted $25 million of

our 5.5 percent junior subordinated convertible debentures in exchange for 2 million shares of our common stock.

Table of Contents

Notes (Continued)

The table below includes information related to stock options that were outstanding at September 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 third quarter weighted-average market price of our common shares.

	September 30, 2008	September 30, 2007
Options excluded (millions)	1.9	1.9
Weighted-average exercise prices of options excluded	$ 37.04	$ 37.56
Exercise price ranges of options excluded	$ 32.05 - $42.29	$ 33.51 - $42.29
Third quarter weighted-average market price	$ 30.22	$ 32.56

Note 7. Employee Benefit Plans

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

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic pension expense:				
Service cost	$ 6	$ 5	$ 17	$ 17
Interest cost	15	13	45	40
Expected return on plan assets	(20)	(18)	(59)	(54)
Amortization of net actuarial loss	3	5	10	14
Net periodic pension expense	$ 4	$ 5	$ 13	$ 17

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Components of net periodic other postretirement benefit expense:				
Service cost	$ 1	$ 1	$ 2	$ 2
Interest cost	5	5	14	13
Expected return on plan assets	(4)	(3)	(10)	(9)
Regulatory asset amortization	1	1	3	4
Net periodic other postretirement benefit expense	$ 3	$ 4	$ 9	$ 10

During the nine months ended September 30, 2008, we contributed $37 million to our pension plans and $11 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $25 million to our pension plans in the remainder of 2008 for a total of approximately $62 million. We presently anticipate making additional contributions of approximately $4 million to our other postretirement benefit plans in 2008 for a total of approximately $15 million.

The assets and liabilities recorded on the Consolidated Balance Sheet at September 30, 2008, representing the funded status of the pension and other postretirement benefit plans, use various assumptions including expected long-term rates of return on plan assets and discount rates. Considering the decline in the overall equity markets during 2008, the expected return on plan assets may not be achieved during 2008. Additionally, the 2008 increase in interest rates on high-quality corporate bonds could result in higher discount rates, resulting in lower plan obligations. As a result, the pension and other postretirement benefit plan assets and liabilities recorded as of September 30, 2008, may not represent the actual funded status of the plans as of that date. The annual measurement of the funded status of the plans will occur as of December 31, 2008. The impact of the differences between actual and assumed outcomes and changes in assumptions will likely cause a significant net actuarial loss and will be recognized in other comprehensive income, net of taxes, and amortized in net periodic benefit expense beginning in 2009.

Table of Contents

Notes (Continued)

Note 8. Inventories

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

	September 30, 2008	December 31, 2007
	(Millions)	
Natural gas liquids (NGLs)	$ 146	$ 66
Natural gas in underground storage	74	45
Materials, supplies and other	104	98
	$ 324	$ 209

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

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

	Letters of Credit at September 30, 2008
	(Millions)
$500 million unsecured credit facilities	$
$700 million unsecured credit facilities	$ 237
$1.5 billion unsecured credit facility	$ 28

Lehman Commercial Paper Inc., which is committed to fund up to $70 million of our $1.5 billion revolving credit facility, has filed for bankruptcy. Lehman Brothers Commercial Bank, which has not filed for bankruptcy, is committed to fund up to $12 million of Williams Partners L.P. s $200 million revolving credit facility. We expect that our ability to borrow under these facilities is reduced by these committed amounts. The committed amounts of other participating banks under these agreements remain in effect and are not impacted by the above.

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 under 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. In September 2008, Transco completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

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. In September 2008, Northwest Pipeline completed an exchange of these notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended.

Notes (Continued)

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 at fair value 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, 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 apply both market and income approaches 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.

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 September 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	$ 1,008	$ 1,705	$ 386	$ 3,099
Other assets	12		10	22
Total assets	$ 1,020	$ 1,705	$ 396	$ 3,121
Liabilities:				
Energy derivatives	$ 950	$ 1,916	$ 104	$ 2,970
Total liabilities	$ 950	$ 1,916	$ 104	$ 2,970

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 the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities.

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. These broker quotes are based on observable market prices at which transactions could currently be executed. 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 September 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 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.

Notes (Continued)

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

	Net Derivatives	Other Assets
	(Millions)	
Balance as of July 1, 2008	$ (641)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	22	
Included in *other comprehensive income* (See Note 13)	870	
Purchases, issuances, and settlements	27	
Transfers in/out of Level 3	4	
Balance as of September 30, 2008	$ 282	$ 10
Unrealized gains included in *income from continuing operations* relating to instruments still held at September 30, 2008	$ 23	$

Level 3 Fair Value Measurements Using Significant Unobservable Inputs
Nine Months Ended September 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*	(7)	
Included in *other comprehensive income* (See Note 13)	210	
Purchases, issuances, and settlements	91	
Transfers in/out of Level 3	2	
Balance as of September 30, 2008	$ 282	$ 10
Unrealized losses included in *income from continuing operations* relating to instruments still held at September 30, 2008	$ (21)	$

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

During 2008, we purchased 13 million shares of our common stock for $474 million at an average cost of $36.76 per share completing our $1 billion common stock repurchase program. This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet. From the program s inception in third-quarter 2007 to its completion in July 2008, we purchased 29 million shares of our common stock reaching the $1 billion limit (including transaction costs) authorized by our Board of Directors. Our overall average cost per share 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 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.

Table of Contents

Notes (Continued)

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 September 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 U.S. 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 September 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, 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.

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. On October 29, 2008, the Tennessee appellate court reversed the state court s dismissal of the plaintiffs claims on federal preemption grounds and sent the case back to the lower court for further proceedings. 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.

Table of Contents

Notes (Continued)

Mobile Bay Expansion

In 2002, an administrative law judge at the FERC issued an initial decision in Transco s 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 September 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 September 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 by the new standard. 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.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 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 CDPHE in June 2008 and paid a $93,300 civil penalty and made a $373,200 contribution to a state environmental program.

Table of Contents

Notes (Continued)

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 the matter with the CDPHE in June 2008 and paid an $11,200 civil penalty and made 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. In July 2008, the NMED issued an NOV to Four Corners that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties 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 in Colorado 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 Clean 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 September 30, 2008, we have accrued liabilities of $9 million for such excess costs.

Other

At September 30, 2008, we have accrued environmental liabilities of $15 million related primarily to our:

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

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.

Notes (Continued)

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 U.S. Department of Justice (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. In November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals and the court held oral argument on September 25, 2008.

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 was seeking actual damages 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. In 2005, the parties agreed to dismiss mismeasurement claims. In September 2008, the court ruled in our favor on motions for summary judgment dismissing various claims. Trial on the remaining breach of contract and accounting claims has been set for November 2008. The amount of any possible liability cannot be reasonably estimated at this time.

Table of Contents

Notes (Continued)

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 WAPI sold the Alaska refinery and ceased shipping on 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.

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.

On August 18, 2008, a counterparty requested a writ of certiorari from the U.S. Supreme Court to appeal the ruling of the D.C. Circuit Court of Appeals.

Redondo Beach taxes

In 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 taxes, interest and penalties were owed related to natural gas used at the generating facility operated by AES Redondo Beach. In connection with the sale of our power business (see Note 2), we and AES Redondo Beach agreed to equally share, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid to the city under protest. In July, 2008, we settled all disputes with the city and they 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.

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.

Table of Contents

Notes (Continued)

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 September 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, which heard oral argument on 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 $23 million to $25 million in additional taxes and interest from January 1, 2003 through September 30, 2008.

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 reached a partial settlement agreement for an amount that was previously accrued. The partial settlement has received preliminary approval by the court, and we anticipate trial in late 2009 on remaining issues related to royalty payment calculation and obligations under specific lease provisions. We are not able to estimate the amount of any additional exposure at this time.

Certain other royalty matters are currently being litigated by other producers with a federal regulatory agency in Colorado and with a state agency in New Mexico. Although we are not a party to these matters, the final outcome of those cases 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.

Table of Contents

Notes (Continued)

At September 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 material 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.

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 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 taxes required to be paid by the 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 $42 million at September 30, 2008. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is $38 million at September 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.

Notes (Continued)

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 September 30, 2008.

Note 13. Comprehensive Income

Comprehensive income is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2008	**2007**	**2008**	**2007**
	(Millions)		**(Millions)**	
Net income	$ 366	$ 198	$ 1,303	$ 765
Other comprehensive income (loss):				
Net unrealized gains on derivative instruments	1,083	131	256	252
Net reclassification into earnings of derivative instrument (gains) losses	62	(32)	142	(476)
Foreign currency translation adjustments	(10)	25	(27)	56
Amortization of pension benefits net actuarial loss	3	5	10	14
Amortization of other postretirement benefits prior service cost			1	1
Other comprehensive income (loss) before taxes	1,138	129	382	(153)
Income tax benefit (provision) on other comprehensive income (loss)	(434)	(40)	(154)	80
Other comprehensive income (loss) before minority interest	704	89	228	(73)
Allocation of other comprehensive income (loss) to minority interest	(12)		(5)	
Other comprehensive income (loss)	692	89	223	(73)
Comprehensive income	$ 1,058	$ 287	$ 1,526	$ 692

Net unrealized gains on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The *net unrealized gains on derivative instruments* are as follows:

	Three months ended September 30,	Nine months ended September 30,

	2008	2007	2008	2007
	(Millions)		(Millions)	
Net unrealized gains (losses) on:				
Forward natural gas purchases and sales	$ 1,034	$ 132	$ 274	$ 284
Forward natural gas liquids sales	50	(1)	(18)	(1)
Forward power purchases and sales				(31)
Other derivative instruments	(1)			
	$ 1,083	$ 131	$ 256	$ 252

Net reclassification into earnings of derivative instrument (gains) losses for the nine months ended September 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.

Table of Contents

Notes (Continued)

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*, *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.

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 September 30, 2008							
Segment revenues:							
External	$ (79)	$ 403	$ 1,442	$ 1,499	$ 2	$	$ 3,267
Internal	962	4	(6)	217	4	(1,181)	
Total revenues	$ 883	$ 407	$ 1,436	$ 1,716	$ 6	$ (1,181)	$ 3,267
Segment profit (loss)	$ 361	$ 173	$ 254	$ 16	$ (2)	$	$ 802
Less equity earnings	5	21	28				54
Segment operating income (loss)	$ 356	$ 152	$ 226	$ 16	$ (2)	$	748
General corporate expenses							(34)
Total operating income							$ 714
Three months ended September 30, 2007							
Segment revenues:							
External	$ (21)	$ 385	$ 1,350	$ 1,141	$ 5	$	$ 2,860
Internal	520	7	10	106	2	(645)	
Total revenues	$ 499	$ 392	$ 1,360	$ 1,247	$ 7	$ (645)	$ 2,860
Segment profit (loss)	$ 169	$ 183	$ 300	$ (67)	$	$	$ 585
Less equity earnings	10	21	21				52

Segment operating income (loss)	$ 159	$ 162	$ 279	$ (67)	$	$ 533
General corporate expenses						(40)
Total operating income						$ 493

23

Table of Contents

Notes (Continued)

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services	Other	Eliminations	Total
				(Millions)			
Nine months ended September 30, 2008							
Segment revenues:							
External	$ (206)	$ 1,200	$ 4,747	$ 4,472	$ 7	$	$ 10,220
Internal	2,813	26		904	11	(3,754)	
Total revenues	$ 2,607	$ 1,226	$ 4,747	$ 5,376	$ 18	$ (3,754)	$ 10,220
Segment profit (loss)	$ 1,287	$ 532	$ 810	$ (9)	$ (2)	$	$ 2,618
Less equity earnings	14	46	67				127
Segment operating income (loss)	$ 1,273	$ 486	$ 743	$ (9)	$ (2)	$	2,491
General corporate expenses							(118)
Total operating income							$ 2,373
Nine months ended September 30, 2007							
Segment revenues:							
External	$ (97)	$ 1,156	$ 3,573	$ 3,411	$ 9	$	$ 8,052
Internal	1,618	22	32	518	11	(2,201)	
Total revenues	$ 1,521	$ 1,178	$ 3,605	$ 3,929	$ 20	$ (2,201)	$ 8,052
Segment profit (loss)	$ 566	$ 513	$ 705	$ (160)	$	$	$ 1,624
Less equity earnings	20	40	36				96
Segment operating income (loss)	$ 546	$ 473	$ 669	$ (160)	$	$	1,528
General corporate expenses							(116)
Total operating income							$ 1,412

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

	Total Assets	
	September 30, 2008	December 31, 2007
	(Millions)	
Exploration & Production (1)	$ 10,362	$ 8,692
Gas Pipeline	9,078	8,624
Midstream Gas & Liquids	7,371	6,604

Gas Marketing Services	4,460	4,437
Other	3,524	3,592
Eliminations	(7,918)	(7,073)
	26,877	24,876
Assets of discontinued operations	16	185
Total	$ 26,893	$ 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 significantly offset by their derivative liabilities. The property, plant and equipment net increase is primarily due to increased drilling activity.

Note 15. Recent Accounting Standards

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.

Notes (Continued)

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. 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 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. The application of this Statement will increase the disclosures in our Consolidated Financial Statements.

In June 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.

Table of Contents

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

Recent Market Events

The recent instability in financial markets has created global concerns about the liquidity of financial institutions and is having overarching impacts on the economy as a whole. In this volatile economic environment, many financial markets, institutions and other businesses remain under considerable stress. In addition, oil and gas prices have recently experienced significant declines. These events are impacting our business. However, we note the following:

- We are reducing our levels of expected capital expenditures.
- As of September 30, 2008, we have approximately $1.5 billion of cash and cash equivalents and nearly $2.6 billion of available capacity under our credit facilities. (See further discussion in Management s Discussion and Analysis of Financial Condition Available Liquidity.)
- We have no significant debt maturities until 2011.
- Considering master netting agreements and collateral support, we do not have significant risk from our net credit exposure to derivative counterparties. (See further discussion in Energy Trading Activities Counterparty Credit Considerations.)

To the extent that these recent events drive sustained lower energy commodity prices, it will negatively impact our future results of operations and cash flow from operations and could result in a further reduction in capital expenditures. These impacts could also include the future nonperformance of counterparties or impairments of goodwill and long-lived assets. In addition, the overall decline in equity markets in 2008 has negatively impacted our employee benefit plan assets and will likely increase expense in future periods. (See Note 7 of Notes to Consolidated Financial Statements.)

Company Outlook

Our plan for 2008 has been focused on disciplined growth. Our plans for the remainder of 2008 and into 2009 have been adjusted in light of lower energy commodity prices and the disruption in the financial markets. At present, we intend to continue our disciplined growth, but the level of our future investment will be adjusted as required to maintain adequate liquidity. Our objectives include continuing to improve EVA® and invest in our businesses in a way that 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:

- Availability of capital;
- Counterparty credit and performance risk;
- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Decreased drilling success or abandonment of projects by third parties served by Midstream and Gas Pipeline;

Table of Contents

Management s Discussion and Analysis (Continued)

- General economic, financial markets, or industry downturn;
- Changes in the current political and regulatory environment;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

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 at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties.

Our *income from continuing operations* for the nine months ended September 30, 2008, increased $563 million compared to the nine months ended September 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 at Exploration & Production on the sale of a contractual right to a production payment on certain future international hydrocarbon production;
- Favorable commodity price margins at Midstream.

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the nine months ended September 30, 2008, increased $929 million compared to the nine months ended September 30, 2007, primarily due to our improved operating results. See additional discussion in Management s Discussion and Analysis of Financial Condition.

Recent Events

In September 2008, Hurricanes Gustav and Ike impacted our operations, primarily at Midstream. We estimate that our segment profit for third-quarter 2008 was decreased by approximately $50 million to $65 million due to downtime and charges for repairs and property insurance deductibles associated with Hurricanes Gustav and Ike. We also estimate that fourth-quarter 2008 pre-tax results will be reduced by approximately $10 million to $20 million due to downtime and reduced volumes. See additional discussion in Results of Operations Segments, Gas Pipeline and Midstream Gas & Liquids.

In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors. (See Note 11 of Notes to Consolidated Financial Statements.)

In 2008, we increased our positions by acquiring undeveloped leasehold acreage, producing properties and gathering facilities in the Piceance basin and undeveloped leasehold acreage and producing properties in the Fort Worth basin. See additional discussion in Results of Operations Segments, Exploration & Production.

In 2008, we recognized pre-tax income of $172 million in *income from discontinued operations* related to our former Alaska operations. (See Note 3 of Notes to Consolidated Financial Statements.)

In 2008, we recognized income of $148 million related to the sale of a contractual right to a production payment on certain future international hydrocarbon production. See additional discussion in Results of Operations Segments, Exploration & Production.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering. See additional discussion in Results of Operations Segments, Gas Pipeline.

Transco s new rates became effective June 1, 2008. See additional discussion in Results of Operations Segments, Gas Pipeline.

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 September 30, 2008, 13 percent of the total assets measured at fair value and four percent of the total liabilities measured at fair value are included in Level 3.

Certain instruments trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value also incorporates the time value of money and credit risk factors including the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash deposits and letters of credit) and our nonperformance risk on our liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

The instruments included in Level 3 at September 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 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.

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations

Consolidated Overview

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

	Three months ended September 30,				Nine months ended September 30,			
	2008	2007	$ Change from 2007*	% Change from 2007*	2008	2007	$ Change from 2007*	% Change from 2007*
	(Millions)				(Millions)			
Revenues	$ 3,267	$ 2,860	+407	+14%	$ 10,220	$ 8,052	+2,168	+27%
Costs and expenses:								
Costs and operating expenses	2,386	2,222	164	7%	7,506	6,245	1,261	20%
Selling, general and administrative expenses	133	107	26	24%	375	317	58	18%
Other income net		(2)	2	100%	(152)	(38)	+114	NM
General corporate expenses	34	40	+6	+15%	118	116	2	2%
Total costs and expenses	2,553	2,367			7,847	6,640		
Operating income	714	493			2,373	1,412		
Interest accrued net	(150)	(162)	+12	+7%	(456)	(494)	+38	+8%
Investing income	65	78	13	17%	175	196	21	11%
Minority interest in income of consolidated subsidiaries	(55)	(29)	26	90%	(157)	(68)	89	131%
Other income net	2	8	6	75%	7	12	5	42%
Income from continuing operations before income taxes	576	388			1,942	1,058		
Provision for income taxes	207	160	47	29%	738	417	321	77%
Income from continuing operations	369	228			1,204	641		
Income (loss) from discontinued operations	(3)	(30)	+27	+90%	99	124	25	20%

Net income	$ 366	$ 198	$ 1,303	$ 765

*+ = 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.

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

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production resulting from both higher net realized average prices and increased production volumes sold. Midstream also experienced higher natural gas liquid (NGL) and olefin production revenues due primarily to higher prices, partially offset by lower volumes.

The increase in *costs and operating expenses* is primarily due to higher costs associated with our NGL and olefin production businesses 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 expenses (SG&A)* primarily includes the impact of higher staffing and compensation at Exploration & Production in support of increased operational activities.

Other income net within *operating income* in third-quarter 2008 includes a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline and $8 million of net gains on foreign currency exchanges at Midstream. These gains are partially offset by a $14 million impairment of certain natural gas producing properties at Exploration & Production.

Other income net within *operating income* in third-quarter 2007 includes income of $12 million associated with a payment received for a terminated firm transportation agreement on Gas Pipeline s Grays Harbor lateral, partially offset by $6 million of net losses on foreign currency exchanges at Midstream.

The increase in *operating income* primarily reflects both higher net realized average prices and continued strong natural gas production growth at Exploration & Production.

Management s Discussion and Analysis (Continued)

Interest accrued net decreased primarily due to increased capitalized interest resulting from an increased level of capital expenditures. Additionally, the decrease was impacted by lower interest rates on debt issuances that occurred late in the fourth quarter 2007 and in the first half of 2008 for which the proceeds were primarily used to retire existing debt bearing higher interest rates.

The decrease in *investing income* is due primarily to a $17 million decrease in interest income largely a result of lower average interest rates in 2008 compared to 2007.

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. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

The increase in *revenues* is primarily due to higher production revenues at Exploration & Production resulting from both higher net realized average prices and increased production volumes sold. Midstream also experienced higher olefin production revenues primarily due to higher prices and volumes as well as increased NGL, olefin and crude marketing and NGL production revenues all due to higher prices, partially offset by lower volumes. In addition, *revenues* increased due to the favorable change in unrealized mark-to-market revenues at Gas Marketing Services primarily as a result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding.

The increase in *costs and operating expenses* is primarily due to increased NGL, olefin, and crude marketing purchases and increased costs associated with our olefin and NGL production businesses 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* includes the impact of higher staffing and compensation at our Exploration & Production and Midstream segments in support of increased operational activities. The increase also includes $11 million in bad debt expense primarily at Exploration & Production.

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, $20 million of net gains on foreign currency exchanges at Midstream, and a gain of $10 million on the sale of certain south Texas assets at Gas Pipeline. These items are partially offset by $21 million higher project development costs at Gas Pipeline and a $14 million impairment of certain natural gas producing properties at Exploration & Production.

Other income net within *operating income* in 2007 includes income of $18 million associated with payments received for a terminated firm transportation agreement on Gas Pipeline s Grays Harbor lateral and income of $17 million from a change in estimate related to a regulatory liability at Northwest Pipeline.

The increase in *operating income* reflects increased net realized average prices, continued strong natural gas production growth and a gain of $148 million on the sale of a contractual right to a production payment at Exploration & Production, partially offset by higher operating costs. The increase also reflects reduced losses in 2008 from legacy derivative contracts that are no longer outstanding at Gas Marketing Services and continued favorable commodity price margins at Midstream, partially offset by higher operating costs.

Interest accrued net decreased primarily due to increased capitalized interest resulting from an increased level of capital expenditures. Additionally, the decrease was impacted by lower interest rates on debt issuances that occurred late in the fourth quarter 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.

Table of Contents

Management s Discussion and Analysis (Continued)

The decrease in investing income is primarily due to $47 million of decreased interest income largely due to lower average interest rates in 2008 compared to 2007, partially offset by an increase in equity earnings of $31 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. See Note 5 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

See Note 3 of Notes to Consolidated Financial Statements for a discussion of the items in *income (loss) from discontinued operations.*

Table of Contents

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Nine Months Ended September 30, 2008

During the first nine 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 42 percent compared to the first nine months of 2007. The domestic net realized average price for the first nine months of 2008 was $7.22 per thousand cubic feet of gas equivalent (Mcfe) compared to $5.09 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 21 percent compared to the first nine months of 2007. The average daily domestic production for the first nine months of 2008 was approximately 1,073 million cubic feet of gas equivalent (MMcfe) compared to 890 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 nine months of 2008 by $699 million compared to 2007. Capital expenditures for 2008 include acquisitions in the Piceance and Fort Worth basins 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 coupled with higher capitalized drilling costs 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. We received this $71 million in October 2008.

In September 2008, we increased our position in the Fort Worth basin by acquiring certain undeveloped leasehold acreage and producing properties for $147 million subject to post-closing adjustments. This acquisition is consistent with our growth strategy of leveraging our horizontal drilling expertise by acquiring and developing low-risk properties. The change in purchase price from the $166 million announced in July 2008 relates to the ongoing process of finalizing title work on a small portion of the acquisition package.

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 $450 million and $550 million.

Table of Contents

Management s Discussion and Analysis (Continued)

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

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production and consumption, and rising concerns about the recent volatility in the global economy and the related impact on natural gas prices. 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 (COGCC) has proposed rules that could alter our drilling schedule and increase our costs of permitting and environmental compliance. We continue to actively monitor the situation and provide input to the COGCC staff responsible for rulemaking. The final rules could become effective as early as April 2009.

Declining Natural Gas Prices

As a result of the recent market events and the recent decline in natural gas prices, we plan to deploy fewer drilling rigs in 2009 compared to 2008. This will reduce capital expenditures and the number of wells drilled in 2009 compared to 2008. However, we still expect approximately 8 to 10 percent production growth in 2009 compared to 2008. We continue to utilize certain derivative instruments to hedge our cash flows from the sales of natural gas production.

Hedging Strategy

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.

For the remainder of 2008 and total year 2009, we have the following agreements and contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Remainder of 2008			2009		
		Volume	Price ($/Mcf)		Volume	Price ($/Mcf)	
		(MMcf/d)	Floor-Ceiling for Collars		(MMcf/d)	Floor-Ceiling for Collars	
Collar agreements	Rockies	160	$6.08	$9.04	150	$6.11	$9.04
Collar agreements	San Juan	220	$6.37	$9.00	245	$6.58	$9.62
Collar agreements	Mid-Continent	80	$7.02	$9.77	95	$7.08	$9.73
NYMEX and basis fixed-price		70	$4.06		106	$3.67	

The following is a summary of our agreements and contracts for daily production for the three and nine months ended September 30, 2008 and 2007:

		2008			2007		
		Volume	Price ($/Mcf)		Volume	Price ($/Mcf)	
		(MMcf/d)	Floor-Ceiling for Collars		(MMcf/d)	Floor-Ceiling for Collars	
Third Quarter:							
Collar agreements	NYMEX				15	$6.50	$8.25
Collar agreements	Rockies	160	$6.08	$9.04	50	$5.65	$7.45
Collar agreements	San Juan	220	$6.37	$9.00	130	$5.98	$9.63
Collar agreements	Mid-Continent	80	$7.02	$9.77	78	$6.82	$10.73
NYMEX and basis fixed-price		70	$3.90		171	$3.75	
Year-to-Date:							
Collar agreements	NYMEX				15	$6.50	$8.25
Collar agreements	Rockies	173	$6.18	$9.18	50	$5.65	$7.45

Collar agreements	San Juan	196	$6.34	$8.94	130	$5.98	$9.63
Collar agreements	Mid-Continent	57	$7.03	$9.71	76	$6.82	$10.78
NYMEX and basis fixed-price		70	$3.94		172	$3.82	

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	**2007**	**2008**	**2007**
	(Millions)		**(Millions)**	
Segment revenues	$ 883	$ 499	$ 2,607	$ 1,521
Segment profit	$ 361	$ 169	$ 1,287	$ 566

Table of Contents

Management s Discussion and Analysis (Continued)

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

Total *segment revenues* increased $384 million, or 77 percent, primarily due to the following:

$316 million, or 79 percent, increase in domestic production revenues reflecting $243 million associated with a 52 percent increase in net realized average prices and $73 million associated with a 18 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. 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 $32 million and $15 million, respectively, related to natural gas liquids (NGL) and approximately $25 million and $11 million, respectively, related to condensate;

$53 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;

$10 million increase in unrealized gains from hedge ineffectiveness.

Total *segment costs and expenses* increased $187 million, primarily due to the following:

$53 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*;

$48 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$35 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

$18 million higher lease operating expenses from the increased number of producing wells, primarily within the Piceance, Powder River, and Fort Worth basins, combined with higher well and lease service expenses and facility expenses;

$14 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 $4 million in bad debt expense;

$14 million impairment in 2008 due to recent drilling results in the Caney Shale in the Arkoma basin.

The $192 million increase in s*egment profit* is primarily due to the 52 percent increase in domestic net realized average prices and the 18 percent increase in domestic production volumes sold, partially offset by the increases in *segment costs and expenses*.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Total *segment revenues* increased approximately $1.1 billion, or 71 percent, primarily due to the following:

$897 million, or 71 percent, increase in domestic production revenues reflecting $633 million associated with a 42 percent increase in net realized average prices and $264 million associated with a 21 percent increase in production volumes sold. The impact of hedge positions on increased net realized average prices includes the

Management s Discussion and Analysis (Continued)

effect of fewer volumes hedged by fixed-price contracts. 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 $75 million and $34 million, respectively, related to natural gas liquids and approximately $60 million and $26 million, respectively, related to condensate;

$168 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.

Total *segment costs and expenses* increased $359 million, primarily due to the following:

$168 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*;

$151 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$84 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

$46 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins combined with higher well and lease service expenses and facility expenses;

$27 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 $9 million in bad debt expense;

$14 million impairment in 2008 due to recent drilling results in the Caney Shale in the Arkoma basin.

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

The $721 million increase in s*egment profit* is primarily due to the 42 percent increase in domestic net realized average prices, the 21 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 Nine Months Ended September 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, we consolidate Williams Pipeline Partners L.P. 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.

Table of Contents

Management s Discussion and Analysis (Continued)

Gulfstream Phase III expansion project

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. Construction began in April 2008 and it was placed into service in September 2008. The extension fully subscribed the remaining 345 thousand dekatherms per day (Mdt/d) of firm capacity on the existing pipeline. Gulfstream s estimated cost of this project is $122 million.

Hurricane Ike

In September 2008, Hurricane Ike impacted several onshore and offshore facilities on Transco s interstate natural gas pipeline system resulting in varying degrees of damage. However, Transco has continued to meet its customer commitments while running at lower-than-normal volumes. We expect the majority of associated costs will be recoverable through insurance, with the remainder recoverable through Transco s rates.

Outlook for the Remainder of 2008

Gulfstream Phase IV expansion project

In September 2007, Gulfstream received FERC approval to construct 17.8 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion was 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 $176 million.

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. The cost of the project is estimated to be up to $200 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 September 30,		Nine months ended September 30,	
	2008	**2007**	**2008**	**2007**
	(Millions)		**(Millions)**	
Segment revenues	$ 407	$ 392	$ 1,226	$ 1,178
Segment profit	$ 173	$ 183	$ 532	$ 513

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

Segment revenues increased $15 million, or 4 percent, due primarily to $22 million higher revenues from transportation imbalance settlements (offset in *costs and operating expenses*) and a $7 million increase in transportation revenue attributable to expansion projects that Transco placed into service in the fourth quarter of 2007. Partially offsetting these increases is a $13 million decrease in revenues associated with a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses increased $7 million, or 4 percent, due primarily to a $22 million increase in costs of transportation imbalance settlements (offset in *segment revenues*) partially offset by a $13 million decrease associated with a 2007 sale of excess inventory gas (offset in *segment revenues*).

Other income net changed unfavorably by $13 million primarily due to the absence in 2008 of $12 million of income recognized in the third quarter of 2007 associated with a payment received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral and $12 million higher project development costs in 2008. Partially offsetting these unfavorable changes is a $10 million gain on the sale of certain south Texas assets in 2008 by Transco.

Management s Discussion and Analysis (Continued)

The $10 million, or 5 percent, decrease in *segment profit* is due to the unfavorable change in *other income net* and a $4 million charge associated with a third-quarter 2008 pipeline rupture, partially offset by the increase in transportation revenue attributable to expansion projects.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Segment revenues increased $48 million, or 4 percent, due primarily to a $56 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 the fourth quarter of 2007. In addition, *segment revenues* increased $31 million due to transportation imbalance settlements (offset in *costs and operating expenses*). Partially offsetting these increases is a $37 million decrease associated with a 2007 sale of excess inventory gas (offset in *costs and operating expenses*).

Costs and operating expenses decreased $4 million, or 1 percent, due primarily to a $37 million decrease associated with a 2007 sale of excess inventory gas (offset in *segment revenues*). The decrease is substantially offset by an increase in costs of $31 million associated with transportation imbalance settlements (offset in *segment revenues*).

Other income net changed unfavorably by $31 million due primarily to the absence in 2008 of $18 million of income recognized in 2007 associated with payments received for a terminated firm transportation agreement on Northwest Pipeline s Grays Harbor lateral and the absence in 2008 of $17 million of income recorded in 2007 for a change in estimate related to a regulatory liability at Northwest Pipeline. In addition, project development costs were $21 million higher in 2008. Partially offsetting these unfavorable changes is a $10 million gain on the sale of certain south Texas assets by Transco in 2008 and a second-quarter 2008 gain of $9 million on the sale of excess inventory gas.

The $19 million, or 4 percent, increase in *segment profit* is due primarily to the increase in transportation revenue, partially offset by the unfavorable change in *other income net* and a $4 million charge associated with a third-quarter 2008 pipeline rupture.

Midstream Gas & Liquids

Overview of Nine Months Ended September 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. We focus 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

During the first three quarters of 2008, strong per-unit NGL margins driven by higher crude prices, which generally correlate to strong NGL prices, in relationship to natural gas prices have contributed significantly to our realized margins. The geographic diversification of Midstream assets also contributed to realized per-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 three and nine months ended September 30, 2008 was 74 cents and 62 cents per gallon (cpg), a 19 percent and 35 percent increase over the same periods in 2007. Our NGL per-unit margin also increased during the third quarter of 2008 from the previous quarter due to higher NGL prices and a change in the mix of NGL products sold, partially offset by higher gas prices. Due to third-party NGL pipeline capacity restrictions during the third quarter of 2008, we had to reduce our recoveries of ethane, which typically has lower per-unit margins than non-ethane NGLs. If we had been able to produce the same mix of ethane and non-ethane NGLs during the third quarter of 2008 as we generally have in prior quarters, the increase in the average per-unit margin would have been lower. NGL margins have exceeded our rolling five-year average for the last six quarters, in spite of strong NGL margins over the last year that have significantly increased our rolling five-year average from approximately 22 cpg at the end of the third quarter of 2007 to 34 cpg at the end of the third quarter of 2008. NGL margins are defined as NGL revenues less BTU replacement cost, plant fuel, transportation and fractionation expense and include the impact of our hedging activities, which are discussed in *Outlook for the Remainder of 2008.*

Table of Contents

Management s Discussion and Analysis (Continued)

NGL sales volumes constrained

Primarily during the third quarter of 2008, we experienced restrictions on the volume of NGLs we could deliver to third-party NGL pipelines in our West region. These restrictions were caused by a lack of third-party NGL pipeline transportation capacity which resulted in us lowering our ethane recoveries to accommodate these restrictions. Beginning early in the fourth quarter of 2008, these restrictions were alleviated as we were able to deliver NGL volumes from one of our Wyoming plants into the new Overland Pass NGL pipeline. We expect the remaining NGL volumes from our Wyoming plants to begin flowing into Overland Pass later in the fourth quarter of 2008.

Hurricanes Gustav and Ike

As a result of Hurricanes Gustav and Ike in September 2008, not only did our Gulf Coast region facilities experience reduced volumes and damage, but our West region was also negatively impacted. We estimate that our segment profit for third-quarter 2008 was decreased by approximately $50 million to $65 million due to downtime and charges for repairs and property insurance deductibles associated with Hurricanes Gustav and Ike. We also estimate that fourth-quarter 2008 segment profit will be reduced by $10 million to $20 million due to downtime and reduced volumes associated with the hurricanes. Other than the Cameron Meadows natural gas processing plant and the Discovery offshore gathering system, our major gathering and processing assets in the Gulf of Mexico returned to full operations by the end of the third quarter. However, certain assets continue to run at reduced volumes as producers work to restore their operations to normal levels. The Cameron Meadows plant sustained significant damage from Hurricane Ike. Operations are suspended while we evaluate the timing and extent of the required repairs. The Discovery offshore system, which we operate and own a 60 percent equity interest in, also sustained hurricane damage and is not accepting offshore gas from producers while repairs are being made. The mainline is scheduled to be repaired and returned to service by early December. However, due to further damage assessments, the repair schedule for a lateral is not yet finalized. In the West region, we had to store NGL inventories due to the hurricane-related suspension of operations at a third-party fractionation facility at Mont Belvieu, Texas. We expect to sell most of this excess inventory in the fourth quarter of 2008 and in early 2009.

Major expansion efforts in growth areas

Consistent with our strategy, we continued construction on the following large-scale assets in growth basins.

Management s Discussion and Analysis (Continued)

Gulf Coast region

The total estimated cost of our major expansion projects in the Gulf Coast region is approximately $810 million, of which approximately $235 million remains to be spent.

- In the deepwater of the Gulf of Mexico, we have completed 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. The pipelines have been commissioned and are ready for production to begin flowing. We expect this project to begin contributing to our segment profit in the fourth quarter of 2008.

- 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.

West region

We expect to spend approximately $590 million in total on our major expansion projects in the West region, of which approximately $410 million remains to be spent. Our two major expansion projects include the new Willow Creek facility and additional capacity at our Echo Springs facility.

- The new Willow Creek facility is 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 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.

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, we consolidate Williams Partners L.P. 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.

- We expect our per-unit NGL margins to continue to exceed our rolling five-year average, although as evidenced by recent events, crude and natural gas prices are highly volatile. We expect lower per-unit margins in the fourth quarter of 2008 compared to the third quarter of 2008 as NGL prices, especially ethane, decline along with crude price declines. We anticipate periods when it will not be economical to recover ethane in the Gulf Coast region, which will reduce our margins. However, we expect continued favorable gas price differentials in the Rocky Mountain area to mitigate per-unit margin declines in the West region. Although NGL products are currently 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, forecasted domestic and global demand for polyethylene has weakened with the recent instability in the economy.

39

Management s Discussion and Analysis (Continued)

We expect a reduction in our segment profit in the fourth quarter of 2008 due to reduced volumes associated with the hurricanes. While we expect business interruption insurance to largely mitigate any losses associated with outages beyond 60 days, the timing to resolve these claims is uncertain. In addition, damage to third-party facilities has idled two of our smaller offshore gathering systems in the Gulf Coast region. If these third-party producers do not or are unable to restore their operations, our assets may become impaired.

We expect significant savings in certain NGL transportation costs in the West region, which are a component of our per-unit NGL margin, as we transition from our current shipping arrangement to transportation on the Overland Pass pipeline. NGL volumes from one of our Wyoming plants began to flow into the Overland Pass pipeline early in the fourth quarter of 2008, and we expect the remaining NGL volumes from the other plant to begin flowing by the end of this year. 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.

We entered into various financial hedging contracts during December 2007, and January and February 2008. Of our forecasted domestic NGL sales for the fourth quarter of 2008, approximately 22 percent have been hedged with collar agreements at an expected weighted average sales price that approximates our average 2007 domestic NGL sales price and approximately four percent 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.

Based on the cost advantage of our propylene and ethylene production processes compared to other production processes which use crude-based feedstocks and our increased ownership interest in the Geismar olefins facility effective July 2007, we anticipate results from our olefins business for the 2008 year to be above 2007 levels. However, margins in our olefins business are highly dependent upon continued demand within the global economy and our cost advantage diminishes as crude prices decline. The significant slow down in domestic and global economies could further reduce the demand for the petrochemical products we produce in both Canada and the United States.

Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee-basis or a keep-whole or percent-of-liquids basis. Such elections may affect our future revenues. Fee-based revenues generally reduce our exposure to commodity price risks, but may also reduce our profitability in high margin environments.

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, we expect our operating expenses to increase.

Final resolution of our negotiations with the Jicarilla Apache Nation (JAN) concerning our gathering system assets located on JAN-owned land will impact our future operating results. During the third quarter of 2008, negotiations with the JAN, which have been ongoing since the expiration of our right-of-way agreement with them on December 31, 2006, expanded from an asset sale to discussions of other alternative arrangements. While the ultimate outcome is unknown at this time, the alternative arrangements could allow us to retain revenue associated with these gathering system assets, although it may also increase annual operating costs.

Period-Over-Period Results

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)		(Millions)	
Segment revenues	$ 1,436	$ 1,360	$ 4,747	$ 3,605
Segment profit (loss)				
Domestic gathering & processing	225	251	661	586
Venezuela	30	22	84	78
Other	23	49	139	103
Indirect general and administrative expense	(24)	(22)	(74)	(62)
Total	$ 254	$ 300	$ 810	$ 705

Table of Contents

Management s Discussion and Analysis (Continued)

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

The $76 million, or 6 percent, increase in *segment revenues* is largely due to:

A $50 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices, partially offset by lower volumes.

A $31 million increase in revenues in our olefins production business due primarily to higher prices, partially offset by lower volumes.

A $16 million increase in fee revenues due primarily to higher Venezuelan processing fee revenues and higher storage and fractionation fee revenues.

These increases are partially offset by a $24 million decrease in revenues from the marketing of NGLs, olefins and crude due primarily to lower NGL and crude volumes, partially offset by higher NGL and crude prices.

Segment costs and expenses increased $128 million, or 12 percent, primarily as a result of:

A $72 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices, partially offset by lower volumes.

A $48 million increase in costs in our olefins production business due primarily to higher feedstock costs, partially offset by lower volumes.

A $24 million increase in operating costs driven by higher repair costs and property insurance deductibles related to the hurricanes and higher depreciation.

A $5 million increase in NGL, olefin and crude marketing purchases due primarily to higher NGL and crude prices and a $14 million write-down of NGL inventories to the lower of cost or market, partially offset by lower volumes.

These increases are partially offset by a $17 million favorable change consisting of $8 million in foreign exchange gains relating to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $9 million in losses in 2007.

The $46 million, or 15 percent, decrease in Midstream s *segment profit* primarily reflects the 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 $26 million decrease in *domestic gathering & processing segment profit* includes a $19 million decrease in the West region and a $7 million decrease in the Gulf Coast region.

The $19 million decrease in the West region s *segment profit* includes:

A $26 million decrease in NGL margins due to significantly lower volumes and higher gas prices, partially offset by higher NGL prices. Due to the previously discussed lack of third-party NGL pipeline transportation capacity, it was necessary to lower our ethane recoveries to accommodate restrictions on the volume of NGLs we could deliver into the pipelines. In addition, as previously discussed, sales volumes were lower as the hurricane-related disruptions at a third-party fractionation facility at Mont Belvieu, Texas resulted in an NGL inventory build-up.

Table of Contents

Management s Discussion and Analysis (Continued)

A $6 million involuntary conversion gain related to insurance recoveries in excess of the carrying value of our Ignacio plant. These insurance recoveries were used to rebuild the plant.

The $7 million decrease in the Gulf Coast region s *segment profit* includes:

$5 million in operating costs related to hurricane repair and property insurance deductibles.

A $4 million increase in NGL margins due to higher NGL prices, partially offset by higher gas prices and lower volumes. Volumes are lower due both to the hurricanes and natural declines in some fields, partially offset by new supplies connected in the deepwater.

Other

The significant components of the $26 million decrease in *segment profit* of our other operations include:

$29 million in lower margins related to the marketing of NGLs and olefins due primarily to a $14 million charge relating to a lower of cost or market adjustment on NGL inventories and greater unfavorable changes in pricing while product was in transit during 2008 as compared to 2007.

$17 million in lower margins in our olefins production business due primarily to lower volumes as a result of third-party operational issues that reduced off-gas supplies to our plant in Canada and higher feedstock prices, partially offset by higher olefin sales prices.

These decreases are partially offset by a $17 million favorable change consisting of $8 million in foreign exchange gains related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $9 million in losses in 2007.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

The $1,142 million, or 32 percent, increase in *segment revenues* is largely due to:

A $385 million increase in revenues in our olefins production business due primarily to higher prices and higher volumes sold associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.

A $375 million increase in revenues from the marketing of NGLs, olefins and crude due primarily to higher NGL and crude prices, partially offset by lower volumes sold.

A $328 million increase in revenues associated with the production of NGLs due primarily to higher NGL prices, partially offset by lower volumes.

A $39 million increase in fee-based revenues due primarily to higher fee-based revenues in Venezuela and the West region.

Segment costs and expenses increased $1,068 million, or 36 percent, primarily as a result of:

A $407 million increase in NGL, olefin and crude marketing purchases due primarily to higher NGL and crude prices, partially offset by lower volumes.

A $347 million increase in costs in our olefins production business due to both higher feedstock prices and higher volumes produced associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007.

A $230 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices.

An $80 million increase in operating costs including higher employee costs, repair costs and property insurance deductibles related to the hurricanes, costs associated with the increase of our ownership interest in the Geismar olefins facility, depreciation and gas transportation expenses in the eastern Gulf of Mexico.

Table of Contents

Management s Discussion and Analysis (Continued)

A $31 million favorable change consisting of $13 million in foreign exchange gains in the first nine months of 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $18 million in losses in the first nine months of 2007.

The $105 million, or 15 percent, increase in Midstream s *segment profit* reflects $31 million higher equity earnings and the 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 $75 million increase in *domestic gathering & processing segment profit* includes a $35 million increase in the West region and a $40 million increase in the Gulf Coast region.

The $35 million increase in our West region s *segment profit* includes:

A $33 million increase in NGL margins due to a significant increase in average per-unit NGL prices, partially offset by a significant increase in costs associated with the production of NGLs reflecting higher natural gas prices and lower volumes sold. The decrease in volumes sold is due primarily to forced reductions in ethane recoveries to accommodate restrictions in third-party NGL pipeline transportation capacity, an increase in inventory during the first quarter of 2008 caused by the transition from product sales at the plant to shipping volumes through a pipeline for sale downstream, an increase in inventory during the third quarter of 2008 related to previously discussed hurricane-related disruptions at a third-party fractionation facility, and lower equity volumes as processing agreements change from keep-whole to fee-based. These decreases were partially offset by a full year of production from the fifth train at our Opal processing plant, which began production in the first quarter of 2007.

A $14 million increase in fee revenues due primarily to new lease revenues from Gas Pipeline for the Parachute lateral transferred to Midstream in December 2007.

A $9 million involuntary conversion gain related to insurance recoveries in excess of the carrying value of our Ignacio plant. These insurance recoveries were used to rebuild the plant.

A $29 million increase in operating costs driven by a $14 million increase in operations and maintenance expenses including higher employee costs and turbine and engine overhaul expenses, higher depreciation, and higher gathering fuel expense.

The $40 million increase in the Gulf Coast region s *segment profit* is primarily due to higher NGL margins, partially offset by higher operating costs and other expenses. The significant components of this increase include:

NGL margins increased $65 million due to significantly higher NGL prices and slightly higher volumes, partially offset by a significant increase in costs associated with the production of NGLs reflecting higher natural gas prices. The volume increase is due primarily to connecting new supplies in the deepwater, offset by reduced volumes related to the hurricanes in the third quarter of 2008.

Operating costs increased $19 million, including $5 million in hurricane repair and property insurance deductibles and $9 million higher gas transportation expenses in the eastern Gulf of Mexico.

Venezuela

Segment profit for our Venezuela assets increased $6 million. The increase is due primarily to $15 million higher fee revenues resulting from gas compression and injection efficiencies and higher gas reimbursement rates, partially offset by $8 million in lower currency exchange gains.

Table of Contents

Management s Discussion and Analysis (Continued)

Other

The significant components of the $36 million increase in *segment profit* of our other operations include:

$38 million in higher margins in our olefins production business due primarily to higher propylene margins, higher ethylene volumes associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007, and higher margins on NGL products produced in our Canadian olefins operations, partially offset by lower volumes at our plant in Canada as a result of third-party operational issues that reduced off-gas supplies.

Higher equity earnings including $15 million higher Discovery Producer Services L.L.C. equity earnings and $12 million higher Aux Sable Liquids Products, L.P. equity earnings primarily due to favorable processing margins.

A $31 million favorable change consisting of $13 million in foreign exchange gains in the first nine months of 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $18 million in losses in the first nine months of 2007.

These increases are partially offset by:

$32 million in lower margins related to the marketing of NGLs and olefins due primarily to a $14 million charge relating to a lower of cost or market adjustment on NGL inventories and unfavorable changes in pricing while product was in transit during 2008 as compared to 2007.

$35 million higher operating costs including higher costs associated with the increase of our ownership interest in the Geismar olefins facility effective July 2007 and $3 million in repair expense at our Geismar plant which was damaged in Hurricane Gustav.

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, related hedges and proprietary trading positions, including certain legacy natural gas contracts and positions. Gas Marketing also provides similar services to third parties, such as producers.

Overview of Nine Months Ended September 30, 2008

Gas Marketing s improved operating results for the first nine months of 2008 compared to the first nine months of 2007 reflect a favorable change in unrealized mark-to-market gains (losses) on derivatives that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The favorable change was largely the result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding. Results for 2008 also include favorable price movements on derivative positions executed to hedge the anticipated withdrawals of natural gas from storage. These gains were partially offset by lower-of-cost-or-market adjustments to the carrying value of the natural gas inventories in storage.

Outlook for the Remainder of 2008

For the remainder of 2008, Gas Marketing will focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment remain in the Gas Marketing segment. Gas Marketing s earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting, primarily those contracts used to hedge the anticipated storage withdrawals.

Table of Contents

Management s Discussion and Analysis (Continued)

Period-Over-Period Results

	Three months ended September 30,		Nine months ended September 30,	
	2008	2007	2008	2007
	(Millions)		(Millions)	
Realized revenues	$ 1,687	$ 1,300	$ 5,363	$ 4,084
Net forward unrealized mark-to-market gains (losses)	29	(53)	13	(155)
Segment revenues	1,716	1,247	5,376	3,929
Costs and operating expenses	1,695	1,312	5,369	4,080
Gross margin	21	(65)	7	(151)
Selling, general and administrative expenses	4	2	15	9
Other expense net	1		1	
Segment profit (loss)	$ 16	$ (67)	$ (9)	$ (160)

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

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. Realized revenues increased $387 million primarily due to an increase in physical natural gas revenue as a result of a 49 percent increase in average prices on physical natural gas sales and an increase in net financial settlements of derivative contracts. The increase is partially offset by a 15 percent decrease in natural gas sales volumes due to increased volumes injected into storage.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The favorable change of $82 million in unrealized mark-to-market revenues is primarily the result of favorable price movements on derivative positions primarily related to our natural gas storage activity.

The $383 million increase in *cost and operating expenses* is primarily due to a 52 percent increase in average prices on physical natural gas purchases. Partially offsetting this increase is a 14 percent decrease in third-party natural gas purchase volumes. The third quarter of 2008 includes a $24 million lower-of-cost-or-market adjustment to inventory, compared to $21 million in the third quarter of 2007.

The $83 million improvement in *segment profit (loss)* is primarily due to the previously described favorable change in unrealized mark-to-market revenues.

Nine months ended September 30, 2008 vs. nine months ended September 30, 2007

Realized revenues increased $1,279 million primarily due to an increase in physical natural gas revenue as a result of a 39 percent increase in average prices on physical natural gas sales and an increase in net financial settlements of derivative contracts. The increase is partially offset by a 7 percent decrease in natural gas sales volumes.

The favorable change of $168 million in unrealized mark-to-market revenues is primarily the result of reduced losses in 2008 from legacy derivative contracts that are no longer outstanding in addition to favorable price movements on derivative positions primarily related to our natural gas storage activity. This change also includes a $10 million favorable impact in 2008 due to considering our own nonperformance risk in estimating the fair value of our derivative liabilities in accordance with the implementation of SFAS 157. (See Note 10 of Notes to Consolidated Financial Statements.)

The $1,289 million increase in *cost and operating expenses* is primarily due to a 41 percent increase in average prices on physical natural gas purchases. Partially offsetting this increase is a 6 percent decrease in natural gas purchase volumes. Year-to-date 2008 includes a $32 million lower-of-cost-or-market adjustment to inventory, compared to a $25 million adjustment in the prior year.

The $151 million improvement in *segment profit (loss)* is primarily due to the previously described favorable change in unrealized mark-to-market revenues and the favorable impact of applying a credit reserve for nonperformance risk on our own derivative liabilities in accordance with the implementation of SFAS 157. These favorable changes were partially offset by a decrease in realized gross margin.

Table of Contents

Management s Discussion and Analysis (Continued)

Other

Period-Over-Period Results

	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)		(Millions)	
Segment revenues	$ 6	$ 7	$ 18	$ 20
Segment profit (loss)	$ (2)	$	$ (2)	$

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

Table of Contents

Management s Discussion and Analysis (Continued)

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of September 30, 2008. We have presented the fair value of assets and liabilities by the period in which they would be realized under their contractual terms and not as a result of a sale. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 3 of Notes to Consolidated Financial Statements.)

Net Assets (Liabilities) Trading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$(26)	$(21)	$	$	$	$(47)

We are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production s forecasted sales of natural gas production and Midstream s forecasted sales of natural gas liquids under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net asset value of $119 million as of September 30, 2008. The chart below reflects the fair value of derivatives held for nontrading purposes as of September 30, 2008, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

Net Assets (Liabilities) Nontrading
(Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$149	$25	$1	$1	$	$176

Counterparty Credit Considerations

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

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At September 30, 2008, we held collateral support, including letters of credit, of $54 million.

Management s Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations (see Note 3 of Notes to Consolidated Financial Statements), as of September 30, 2008, is summarized below.

Counterparty Type	**Investment Grade (a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 1	$ 3
Energy marketers and traders	175	1,238
Financial institutions	1,867	1,870
	$ 2,043	3,111
Credit reserves		(1)
Gross credit exposure from derivatives		$ 3,110

We assess our credit exposure on a net basis to reflect master netting agreements with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2008, is summarized below.

Counterparty Type	**Investment Grade (a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 1	$ 3
Energy marketers and traders	71	76
Financial institutions	360	360
	$ 432	439
Credit reserves		(1)
Net credit exposure from derivatives		$ 438

(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum Standard & Poor s rating of

BBB- or Moody s Investors Service rating of Baa3 in investment grade.

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition

Outlook

We entered 2008 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

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

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

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

We estimate capital and investment expenditures will total \$3.375 billion to \$3.575 billion in 2008, with \$782 million to \$982 million to be incurred over the remainder of the year. Of the total estimated 2008 capital expenditures, \$2.35 billion to \$2.45 billion is related to Exploration & Production. Also within the total estimated expenditures for 2008 is approximately \$170 million to \$200 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance. Capital and investment expenditures are expected to range from \$2.8 billion to \$3.1 billion in 2009.

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. We also expect to maintain our investment grade status. We expect to maintain liquidity of at least \$1 billion from cash and cash equivalents and unused revolving credit facilities. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, which is estimated to be between \$3.1 billion and \$3.3 billion in 2008, and cash and cash equivalents on hand as needed. Cash flow from operations is expected to range from \$2.4 billion to \$3.1 billion in 2009. We have also historically provided for additional funding needs through the issuance of debt and sales of units of Williams Partners L.P. and Williams Pipeline Partners L.P. However, as a result of credit market conditions at the time of this filing, these sources of funding are considered economically prohibitive and are unlikely to be utilized in this economic environment.

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

- The impact of the general economic downturn, including associated volatility and our ability to access capital markets (see Recent Market Events).

- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, both our Exploration & Production and Midstream segments utilize hedging programs to manage commodity price risk.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of September 30, 2008, we estimate our exposure to additional margin requirements through the remainder of 2008 to be no more than \$26 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements).

Table of Contents

Management s Discussion and Analysis (Continued)

Liquidity

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

Available Liquidity

		September 30, 2008 (Millions)
Cash and cash equivalents (1)	$	1,524
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion		963
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility (2)		1,402
Available capacity under Williams Partners L.P. s $450 million five-year senior unsecured credit facility (3)		188
	$	4,077

(1) *Cash and cash equivalents* includes $48 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $598 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations. The remainder of our *cash and cash equivalents* is primarily held in government-backed instruments.

(2) Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. We expect that the ability of both Northwest Pipeline and Transco to borrow under this facility is reduced by approximately $19 million each due to the bankruptcy of a participating bank. We also expect that our consolidated ability to borrow under this facility is reduced by a total of $70 million, including the reductions related to Northwest Pipeline and Transco. The available liquidity in the table above reflects this $70 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

(3) This facility is only available to Williams Partners L.P. We expect that Williams Partners

L.P. s ability to borrow under this facility is reduced by $12 million. The available liquidity in the table above reflects this $12 million reduction. (See Note 9 of Notes to Consolidated Financial Statements.) The committed amounts of other participating banks under this agreement remain in effect and are not impacted by this reduction.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities.

Williams Partners L.P. has a shelf registration statement available for the issuance of $1.17 billion aggregate principal amount of debt and limited partnership unit securities.

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

Exploration & Production has an unsecured credit agreement with certain banks that serves to reduce our use of cash and other credit facilities for margin requirements related to our hedging activities as well as lower transaction fees. In June 2008, the agreement was extended through December 2013.

The above table does not include a $10 million auction rate security that is classified within *Investments* due to recent auction failures. We have the intent and ability to hold this investment grade security until we are able to realize its face value. We hold no other auction rate securities at September 30, 2008.

Credit ratings

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

Moody s Investors Service rates our senior unsecured debt at Baa3 with a stable ratings outlook. With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates tha an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 ranking at the lower end of the category.

Table of Contents

Management s Discussion and Analysis (Continued)

Fitch Ratings rates our senior unsecured debt at BBB- with a stable ratings outlook. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. Fitch may add a + or a sign to show the obligor s relative standing within a major rating category.

Sources (Uses) of Cash

	Nine months ended September 30, 2008	Nine months ended September 30, 2007
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 2,606	$ 1,677
Financing activities	(316)	(508)
Investing activities	(2,465)	(1,983)
Decrease in cash and cash equivalents	$ (175)	$ (814)

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2008, increased from the same period in 2007 due primarily to the improvement in our operating results. Significant transactions impacting our *net cash provided by operating activities* in 2008 include:

$128 million of cash received related to a favorable ruling from the Alaska Supreme Court (see Note 3 of Notes to Consolidated Financial Statements).

$144 million of required refunds paid by Transco related to a general rate case with the FERC (see Results of Operations Segments, Gas Pipeline).

Financing activities

Our *net cash used by financing activities* for the nine months ended September 30, 2008, decreased from the same period in 2007. Significant transactions include:

$362 million of cash received in 2008 from the completion of the Williams Pipeline Partners L.P. initial public offering (see Note 2 of Notes to Consolidated Financial Statements).

$474 million of cash payments for the repurchase of our common stock in 2008 (see Note 11 of Notes to Consolidated Financial Statements) compared to $234 million of our common stock repurchased in 2007.

Net debt proceeds of $40 million in 2008 related primarily to $75 million of net cash received from debt transactions in the Gas Pipeline segment (see Note 9 of Notes to Consolidated Financial Statements). In 2007 we had net debt payments of $134 million.

Quarterly dividends paid on common stock totaled $186 million in 2008 compared to $174 million in 2007.

Investing activities

Our *net cash used by investing activities* for the nine months ended September 30, 2008, increased from the same period in 2007. Significant transactions include:

In 2008, capital expenditures totaled $2.6 billion and were largely related to Exploration & Production s drilling activity. This total includes Exploration & Production s acquisitions of certain interests in the Piceance and Fort Worth basins for $285 million and $147 million, respectively (see Results of Operations Segments

Exploration & Production). In 2007, capital expenditures totaled $2.1 billion and were largely related to Exploration & Production s drilling activity, mostly in the Piceance basin.

$148 million of cash received in 2008 from Exploration & Production s sale of a contractual right to a production payment (see Note 4 of Notes to Consolidated Financial Statements).

Table of Contents

Management s Discussion and Analysis (Continued)

We purchased \$105 million in investments in 2008, including \$82 million related to our Gulfstream equity investment.

We purchased \$304 million and received \$353 million from the sale of auction rate securities in 2007. These were utilized as a component of our overall cash management program.

Off-balance sheet financing arrangements and guarantees of debt

We have various guarantees which are disclosed in Note 12 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first nine months of 2008. (See Note 9 of Notes to Consolidated Financial Statements.)

Commodity Price Risk

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

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

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. Our value at risk for contracts held for trading purposes was $.2 million at September 30, 2008, and $1 million at December 31, 2007.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	Natural gas sales
Midstream	Natural gas purchases NGL sales
Gas Marketing Services	Natural gas purchases and sales

The value at risk for derivative contracts held for nontrading purposes was $36 million at September 30, 2008, and $24 million at December 31, 2007. Derivative contracts included in our assets and liabilities of discontinued operations are included in the nontrading portfolio, but these had a value at risk of zero for both periods.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any changes in the fair value of the effective portion of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Table of Contents

Item 4
Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

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

Third-Quarter 2008 Changes in Internal Controls Over Financial Reporting

There have been no changes during the third-quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Table of Contents

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 12 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2007, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed except as set forth below:

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Specifically, 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 a material effect on our results of operations. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

Recent events in the global credit markets have created a shortage in the availability of credit.

Global credit markets have recently experienced a shortage in overall liquidity and a resulting disruption in the availability of credit. While we cannot predict the occurrence of future disruptions or how long the current circumstances may continue, we believe cash on hand and cash provided by operating activities, as well as availability under our existing financing agreements will provide us with adequate liquidity for the foreseeable future. However, our ability to borrow under our existing financing agreements, including our bank credit facilities, could be impaired if one or more of our lenders fail to honor its contractual obligation to lend to us. Continuing or additional disruptions, including the bankruptcy or restructuring of certain financial institutions, may adversely affect the availability of credit already arranged and the availability and cost of credit in the future.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts consists of wholesale contracts to buy and sell commodities, including contracts for natural gas, natural gas liquids and other commodities that are settled by the delivery of the commodity or cash throughout the United States. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our businesses, we often extend credit to our counterparties. Despite performing credit analysis prior to extending credit, we are exposed to the risk that we might not be able to collect amounts owed to

Table of Contents

us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty s obligation is inadequate, we will suffer a loss. A general downturn in the economy and tightening of global credit markets could cause more of our counterparties to fail to perform than we have expected.

Our debt agreements impose restrictions on us that may adversely affect our ability to operate our business.

Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, make certain distributions, and incur additional debt. In addition, our debt agreements contain, and those we enter into in the future may contain, financial covenants and other limitations with which we will need to comply. Our ability to comply with these covenants may be affected by many events beyond our control, and we cannot assure you that our future operating results will be sufficient to comply with the covenants or, in the event of a default under any of our debt agreements, to remedy that default.

Our failure to comply with the covenants in our debt agreements and other related transactional documents could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. An event of default or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our existing debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance existing debt obligations will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet its debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Our costs and funding obligations for our defined benefit pension plans and costs for our other postretirement benefit plans are affected by factors beyond our control.

We have defined benefit pension plans covering substantially all of our U.S. employees and other postretirement benefit plans covering certain eligible participants. The timing and amount of our funding requirements under the defined benefit pension plans depend upon a number of factors, including changes to pension plan benefits as well as factors outside of our control, such as asset returns, interest rates and changes in pension laws. Changes to these and other factors that can significantly increase our funding requirements could have a significant adverse effect on our financial condition. The amount of expenses recorded for our defined benefit pension plans and other postretirement benefit plans is also dependent on changes in several factors, including market interest rates and the returns on plan assets. Significant changes in any of these factors may adversely impact our future results of operations.

Table of Contents

***The continuation of recent economic conditions, including disruptions in the global credit markets, could adversely affect our results of operations*.**

The slowdown in the economy and the significant disruptions and volatility in global credit markets have the potential to negatively impact our businesses in many ways. Included among these potential negative impacts are reduced demand and lower prices for our products and services, increased difficulty in collecting amounts owed to us by our customers and a reduction in our credit ratings (either due to tighter rating standards or the negative impacts described above), which could result in reducing our access to credit markets, raising the cost of such access or requiring us to provide additional collateral to our counterparties.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs[2]
July 1 July 31, 2008	2,959,951	$ 36.97	2,959,951	
August 1 August 31, 2008				
September 1 September 30, 2008				
Total	2,959,951	$ 36.97	2,959,951	

1 We announced a stock repurchase program on July 20, 2007. Our board of directors authorized the repurchase of up to $1 billion of the company s common stock. The stock repurchase

program had no expiration date.

[2] In July 2008, we completed our stock repurchase program by reaching the $1 billion limit authorized by our Board of Directors.

Item 5. Other Information

During the third quarter of 2008, we made responsive filings as required by law with federal antitrust regulators regarding notice we received that Carl C. Icahn and three affiliated entities were seeking statutory pre-clearance to own shares of our common stock in amounts totaling between $442 million and $2.018 billion.

Item 6. Exhibits

The following documents are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Copies of the document have been included herewith for the exhibits denoted with an asterisk.

Exhibit 3 The Williams Companies, Inc. By-laws, as amended on September 18, 2008 (filed on September 24, 2008 as Exhibit 3.1 to our current report on Form 8-K) and incorporated herein by reference.

Exhibit 10.1 Form of Indemnification Agreement effective as of September 18, 2008, among The Williams Companies, Inc. and directors and officers of The Williams Companies, Inc. (filed on September 24, 2008 as Exhibit 10.1 to our current report on Form 8-K) and incorporated herein by reference.

*Exhibit 10.2 Summary of Non-Management Director Compensation Action.

*Exhibit 12 Computation of Ratio of Earnings to Fixed Charges.

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

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

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

Table of Contents

SIGNATURE

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

THE WILLIAMS COMPANIES, INC.

(Registrant)

/s/ Ted T. Timmermans

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

November 6, 2008

Table of Contents

EXHIBIT INDEX

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