WILLIAMS COMPANIES INC
Form 10-Q
October 28, 2010

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

(Mark One)

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

For the quarterly period ended September 30, 2010

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act.) Yes o No þ

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

Class	Outstanding at October 25, 2010
Common Stock, $1 par value	584,774,635 Shares

The Williams Companies, Inc.
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Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements relate to anticipated financial performance, management s plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters. 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 that 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, seeks, could, may, should, continues, estimates, expects, forecasts, intends, might, goals, obj potential, projects, scheduled, will or other similar expressions. These forward-looking statements are based on management s beliefs and assumptions and on information currently available to management and 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;

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- Natural gas and natural gas liquids prices and demand.

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 report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- Availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future natural gas reserves), market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates, fluctuation in foreign exchange, and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- 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 and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation, and rate proceedings;
- Our costs and funding obligations for defined benefit pension plans and other postretirement benefit plans;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risk of our customers;
- 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;
- 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, 2009, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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

(Millions, except per-share amounts)	Three months ended September 30, 2010	Three months ended September 30, 2009*	Nine months ended September 30, 2010	Nine months ended September 30, 2009*
Revenues:				
Williams Partners	$ 1,291	$ 1,181	$ 4,116	$ 3,219
Exploration & Production	1,012	879	3,090	2,664
Other	238	222	778	550
Intercompany eliminations	(237)	(184)	(792)	(504)
Total revenues	2,304	2,098	7,192	5,929
Segment costs and expenses:				
Costs and operating expenses	1,752	1,537	5,397	4,373
Selling, general, and administrative expenses	123	126	356	380
Impairments of goodwill and long-lived assets	1,681		1,681	5
Other (income) expense net	(4)	1	(17)	28
Total segment costs and expenses	3,552	1,664	7,417	4,786
General corporate expenses	43	40	173	118
Operating income (loss):				
Williams Partners	319	317	1,026	833
Exploration & Production	(1,608)	96	(1,369)	278
Other	41	21	118	32
General corporate expenses	(43)	(40)	(173)	(118)
Total operating income (loss)	(1,291)	394	(398)	1,025
Interest accrued	(158)	(168)	(476)	(497)
Interest capitalized	13	15	43	57
Investing income net	68	39	162	2
Early debt retirement costs			(606)	
Other expense net	(4)	(1)	(12)	(2)
Income (loss) from continuing operations before income taxes	(1,372)	279	(1,287)	585
Provision (benefit) for income taxes	(151)	87	(142)	223
Income (loss) from continuing operations	(1,221)	192	(1,145)	362
Income (loss) from discontinued operations	(5)	2	(5)	(223)
Net income (loss)	(1,226)	194	(1,150)	139
Less: Net income attributable to noncontrolling interests	37	51	121	26

Net income (loss) attributable to The Williams Companies, Inc.	$ (1,263)	$ 143	$ (1,271)	$ 113
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	$ (1,258)	$ 141	$ (1,266)	$ 266
Income (loss) from discontinued operations	(5)	2	(5)	(153)
Net income (loss)	$ (1,263)	$ 143	$ (1,271)	$ 113
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ (2.15)	$ .24	$ (2.16)	$ .45
Income (loss) from discontinued operations	(.01)		(.01)	(.26)
Net income (loss)	$ (2.16)	$ .24	$ (2.17)	$ .19
Weighted-average shares (thousands)	584,744	583,103	584,365	581,121
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ (2.15)	$ .24	$ (2.16)	$ .45
Income (loss) from discontinued operations	(.01)		(.01)	(.26)
Net income (loss)	$ (2.16)	$ .24	$ (2.17)	$ .19
Weighted-average shares (thousands)	584,744	590,059	584,365	588,693
Cash dividends declared per common share	$ .125	$ .11	$ .36	$ .33

* Recast as discussed in Note 2.

See accompanying notes.

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

(Dollars in millions, except per-share amounts)	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,015	$ 1,867
Accounts and notes receivable (net of allowance of $15 at September 30, 2010 and $22 at December 31, 2009)	744	829
Inventories	270	222
Derivative assets	572	650
Other current assets and deferred charges	202	225
Total current assets	2,803	3,793
Investments	1,317	886
Property, plant, and equipment, at cost	28,699	27,625
Accumulated depreciation, depletion, and amortization	(9,790)	(8,981)
Property, plant, and equipment net	18,909	18,644
Derivative assets	250	444
Goodwill	8	1,011
Other assets and deferred charges	561	502
Total assets	$ 23,848	$ 25,280
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 869	$ 934
Accrued liabilities	929	948
Derivative liabilities	243	578
Long-term debt due within one year	508	17
Total current liabilities	2,549	2,477
Long-term debt	8,002	8,259
Deferred income taxes	3,496	3,656
Derivative liabilities	165	428
Other liabilities and deferred income	1,460	1,441
Contingent liabilities and commitments (Note 12)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 619 million shares issued at September 30, 2010 and 618 million shares issued at December 31, 2009)	619	618

Capital in excess of par value	7,991	8,135
Retained earnings (deficit)	(578)	903
Accumulated other comprehensive income (loss)	34	(168)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	7,025	8,447
Noncontrolling interests in consolidated subsidiaries	1,151	572
Total equity	8,176	9,019
Total liabilities and equity	$ 23,848	$ 25,280

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Statement of Changes in Equity
(Unaudited)

	Three months ended September 30,					
	2010			2009		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance*	$ 7,979	$ 1,047	$ 9,026	$ 8,324	$ 529	$ 8,853
Comprehensive income (loss):						
Net income (loss)	(1,263)	37	(1,226)	143	51	194
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	71	(5)	66	(167)		(167)
Foreign currency translation adjustments	21		21	50		50
Pension and other postretirement benefits net	5		5	7		7
Total other comprehensive income (loss)	97	(5)	92	(110)		(110)
Total comprehensive income (loss)	(1,166)	32	(1,134)	33	51	84
Cash dividends common stock	(73)		(73)	(64)		(64)
Dividends and distributions to noncontrolling interests		(33)	(33)		(32)	(32)
Stock-based compensation, net of tax	12		12	14		14
Issuance of common stock from 5.5% debentures conversion	1		1			
Sale of limited partner units of consolidated partnership		380	380			
Changes in Williams Partners L.P. ownership interest (Note 2)	275	(275)				
Other	(3)		(3)			
Ending balance	$ 7,025	$ 1,151	$ 8,176	$ 8,307	$ 548	$ 8,855

	Nine months ended September 30,					
	2010			2009		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 8,447	$ 572	$ 9,019	$ 8,440	$ 614	$ 9,054
Comprehensive income (loss):						
Net income (loss)	(1,271)	121	(1,150)	113	26	139

Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	176	(2)	174	(202)		(202)
Foreign currency translation adjustments	11		11	69		69
Pension and other postretirement benefits net	15		15	19		19
Total other comprehensive income (loss)	202	(2)	200	(114)		(114)
Total comprehensive income (loss)	(1,069)	119	(950)	(1)	26	25
Cash dividends common stock	(210)		(210)	(192)		(192)
Dividends and distributions to noncontrolling interests		(99)	(99)		(97)	(97)
Stock-based compensation, net of tax	37		37	32		32
Issuance of common stock from 5.5% debentures conversion	1		1	28		28
Sale of limited partner units of consolidated partnership		380	380			
Changes in Williams Partners L.P. ownership interest (Note 2)	(179)	179				
Other	(2)		(2)		5	5
Ending balance	$ 7,025	$ 1,151	$ 8,176	$ 8,307	$ 548	$ 8,855

* Revised as discussed in Note 2.

See accompanying notes.

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

(Millions)	Nine months ended September 30, 2010	2009
OPERATING ACTIVITIES:		
Net income (loss)	$ (1,150)	$ 139
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion, and amortization	1,101	1,087
Provision (benefit) for deferred income taxes	(190)	84
Provision for loss on goodwill, investments, property and other assets	1,720	351
Provision for doubtful accounts and notes	(6)	51
Amortization of stock-based awards	37	36
Early debt retirement costs	606	
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	92	179
Inventories	(49)	23
Margin deposits and customer margin deposits payable	6	(29)
Other current assets and deferred charges	5	3
Accounts payable	(72)	(76)
Accrued liabilities	(94)	(199)
Changes in current and noncurrent derivative assets and liabilities	(30)	43
Other, including changes in noncurrent assets and liabilities	(35)	66
Net cash provided by operating activities	1,941	1,758
FINANCING ACTIVITIES:		
Proceeds from long-term debt	4,179	595
Payments of long-term debt	(3,953)	(31)
Proceeds from sale of limited partner units of consolidated partnership	380	
Dividends paid	(210)	(192)
Dividends and distributions paid to noncontrolling interests	(99)	(97)
Payments for debt issuance costs	(66)	(7)
Premiums paid on early debt retirements	(574)	
Changes in restricted cash		34
Changes in cash overdrafts	29	(47)
Other net	(7)	6
Net cash provided (used) by financing activities	(321)	261
INVESTING ACTIVITIES:		
Capital expenditures*	(2,111)	(1,829)
Purchases of investments/advances to affiliates	(459)	(132)
Distribution from Gulfstream Natural Gas System, L.L.C.		148
Other net	98	(5)

Net cash used by investing activities	(2,472)	(1,818)
Increase (decrease) in cash and cash equivalents	(852)	201
Cash and cash equivalents at beginning of period	1,867	1,439
Cash and cash equivalents at end of period	$ 1,015	$ 1,640

* Increases to property, plant, and equipment	$ (2,072)	$ (1,713)
Changes in related accounts payable and accrued liabilities	(39)	(116)
Capital expenditures	$ (2,111)	$ (1,829)

See accompanying notes.

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

Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 26, 2010. The accompanying unaudited financial statements include all normal recurring adjustments and others, including impairments of goodwill and assets, that, in the opinion of our management, are necessary to present fairly our financial position at September 30, 2010, results of operations and changes in equity for the three and nine months ended September 30, 2010 and 2009 and cash flows for the nine months ended September 30, 2010 and 2009.

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.

On February 17, 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to Williams Partners L.P. (WPZ), our consolidated master limited partnership, and restructuring our debt (see Note 9). As discussed further in Note 2, we have revised our segment presentation as a result of this strategic restructuring.

Note 2. Basis of Presentation

Strategic Restructuring

Our strategic restructuring completed during the first quarter of 2010 resulted in contributing businesses that were in our previously reported Gas Pipeline and Midstream Gas & Liquids (Midstream) segments into our consolidated master limited partnership, WPZ. The contributed Gas Pipeline businesses included 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 65 percent of Northwest Pipeline GP (Northwest Pipeline), and 24.5 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). We also contributed our general and limited partner interests in Williams Pipeline Partners L.P. (WMZ), which owned the remaining 35 percent of Northwest Pipeline (see *Master Limited Partnerships* section below). The contributed Midstream businesses included significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, as well as a business in Pennsylvania s Marcellus Shale region, and various equity investments in domestic processing and fractionation assets. Our remaining 25.5 percent ownership interest in Gulfstream and our Canadian, Venezuelan, and olefins operations were excluded from the transaction. Additionally, our Exploration & Production segment was not included in this transaction.

As a result of the restructuring, we have changed our segment reporting structure to align with the new parent-level focus employed by our chief operating decision-maker considering the resource allocation and governance associated with managing WPZ as a distinctly separate entity. Beginning first quarter 2010, our reportable segments are Williams Partners, Exploration & Production, and Other.

William Partners consists of our consolidated master limited partnership WPZ, including the gas pipeline and midstream businesses that were contributed as part of our previously described strategic restructuring. WPZ also includes other significant midstream operations and investments in the Four Corners and Gulf Coast regions, as well as a natural gas liquids (NGL) fractionator and storage facilities near Conway, Kansas.

Exploration & Production includes natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, development activities in the Eastern portion of the United States and oil and natural gas interests in South America. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing to third parties, such as producers. Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges not utilized for our own production.

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Notes (Continued)

Other includes our Canadian midstream and domestic olefins operations, a 25.5 percent interest in Gulfstream, as well as corporate operations.

Prior periods have been recast to reflect this revised segment presentation.

Master Limited Partnerships

The change in WPZ ownership between us and the noncontrolling interests as a result of our previously discussed strategic restructuring has been accounted for as an equity transaction, resulting in a $454 million decrease to *capital in excess of par value* and a corresponding increase to *noncontrolling interest in consolidated subsidiaries.*

For the first and second quarter of 2010, this amount related to the change between our ownership interest and the noncontrolling interests resulting from the restructuring was reported as $800 million. During the third quarter of 2010, we determined that this amount was incorrect. This error resulted in a $346 million overstatement of *noncontrolling interests in consolidated subsidiaries* and a $346 million understatement of *capital in excess of par value* in the first and second quarter. The error did not impact *total equity*, key financial covenants, any earnings or cash flow measures or any other key internal measures. The beginning balances for the three months ended September 30, 2010, in the Consolidated Statement of Changes in Equity have been adjusted for the correction and amounts related to activity for the third quarter 2010 have been properly reported. The year-to-date amount presented as *Changes in Williams Partners L.P. ownership interest* in the Consolidated Statement of Changes in Equity represents the originally reported $800 million amount, adjusted for the correction and subsequent third quarter 2010 activity, which is further described below.

On May 24, 2010, WPZ and WMZ entered into a merger agreement that was consummated on August 31, 2010. As a result, WMZ unitholders, except WMZ s general partner, received 0.7584 WPZ common units for each WMZ common unit owned at the effective time of the merger. As a result of the merger, WMZ is wholly owned by WPZ and is no longer publicly traded. In addition, WPZ now owns 100 percent of Northwest Pipeline GP.

During the third quarter, WPZ completed an equity offering that resulted in net proceeds of $380 million. Following this transaction and the previously mentioned merger between WPZ and WMZ, we hold a 77 percent interest in WPZ, comprised of an approximate 75 percent limited partner interest and all of WPZ s 2 percent general partner interest. As part of the equity offering, WPZ granted an option to the underwriters to purchase up to an additional 1,387,500 common units to cover over-allotments. Subsequent to the third quarter, this option was exercised, with minimal impact to our ownership percentage.

The merger and equity offering resulted in changes in ownership between us and the noncontrolling interests that have been accounted for as equity transactions, resulting in an aggregate $275 million increase in *capital in excess of par* and a corresponding decrease in *noncontrolling interest in consolidated subsidiaries*.

We expect WPZ to continue to be self-funding and continue to maintain separate lines of bank credit and cash management accounts. Cash distributions from WPZ to us, including any associated with our incentive distribution rights, are expected to occur through the normal partnership distributions from WPZ to all partners.

Discontinued Operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of certain of our Venezuela operations and other former businesses as discontinued operations. (See Note 3.)

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

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Notes (Continued)

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010	2009
	(Millions)		(Millions)	
Loss from discontinued operations before impairments, gain on deconsolidation and income taxes	$ (6)	$	$ (2)	$ (84)
Impairments				(211)
Gain on deconsolidation				9
(Provision) benefit for income taxes	1	2	(3)	63
Income (loss) from discontinued operations	$ (5)	$ 2	$ (5)	$ (223)
Income (loss) from discontinued operations:				
Attributable to noncontrolling interests	$	$	$	$ (70)
Attributable to The Williams Companies, Inc.	$ (5)	$ 2	$ (5)	$ (153)

Loss from discontinued operations before impairments, gain on deconsolidation and income taxes for the nine months ended September 30, 2009, primarily includes losses from our discontinued Venezuela operations, including $48 million of bad debt expense and a $30 million net charge related to the write-off of certain deferred charges and credits. Offsetting these losses is a $15 million gain related to our former coal operations.

Impairments for the nine months ended September 30, 2009, reflects an impairment of our Venezuela property, plant, and equipment. (See Note 10.)

(Provision) benefit for income taxes for the nine months ended September 30, 2009, includes a $76 million benefit from the reversal of deferred tax balances related to our discontinued Venezuela operations.

Note 4. Asset Sales, Impairments and Other Accruals

The following table presents significant gains or losses reflected in *impairments of goodwill and long-lived assets* and *other (income) expense net* within *segment costs and expenses*:

	Three months ended September 30, 2010	2009	Nine months ended September 30, 2010	2009
	(Millions)		(Millions)	
Williams Partners				
Involuntary conversion gains	$ (7)	$ (5)	$ (18)	$ (4)
Exploration & Production				
Impairment of goodwill	1,003		1,003	
Impairments of producing properties and acquired unproved reserves	678		678	5
Penalties from early release of drilling rigs				32
Gains on sales of certain assets	(13)		(13)	

Impairments of goodwill and certain properties

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we performed an interim impairment assessment of our capitalized costs related to goodwill and domestic properties at Exploration & Production. As a result of these assessments, we recorded an impairment of goodwill, as noted above, and impairments of our capitalized costs of certain natural gas producing properties in the Barnett Shale of $503 million and capitalized costs of certain acquired unproved reserves in the Piceance Highlands acquired in 2008 of $175 million. See Note 10 for a further discussion of the impairments.

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Notes (Continued)

Additional Items

We completed a strategic restructuring transaction in 2010 that involved significant debt issuances, retirements and amendments (see Note 9). We incurred significant costs related to these transactions, as follows:

- $606 million of early debt retirement costs consisting primarily of cash premiums of $574 million;

- $45 million of other transaction costs reflected in *general corporate expenses,* of which $7 million is attributable to noncontrolling interests;

- $4 million of accelerated amortization of debt costs related to the amendments of credit facilities, reflected in *other expense net* below *operating income (loss)*.

Considering the deteriorating circumstances in Venezuela, Other recorded a $75 million impairment charge in 2009 related to an other-than-temporary loss in value associated with our Venezuelan investment in Accroven SRL (Accroven), which is reflected within *investing income net* at Other. (See Note 10.) In June 2010, we sold our 50 percent interest in Accroven to Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $30 million and $43 million were received in the three months and nine months ended September 30, 2010, respectively. These receipts are reflected within *investing income net* at Other. The remainder of the proceeds is due in six quarterly payments beginning October 31, 2010. We are currently recognizing the resulting gain as cash is received.

Exploration & Production recorded $15 million of exploratory dry hole costs in third-quarter 2010, which is included within *costs and operating expenses*.

Exploration & Production recorded an $11 million impairment in 2009 related to a Venezuelan cost-based investment, which is included within *investing income net*. (See Note 10.)

Exploration & Production recognized $11 million of income in 2009 related to the recovery of certain royalty overpayments from prior periods, which is reflected within *revenues*.

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Notes (Continued)

Note 5. Provision (Benefit) for Income Taxes

The *provision (benefit) for income taxes* from continuing operations includes:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Current:				
Federal	$ 66	$ (12)	$ 21	$ 44
State	8	(2)	(1)	5
Foreign	15	7	28	21
	89	(7)	48	70
Deferred:				
Federal	(219)	83	(180)	140
State	(23)	11	(17)	18
Foreign	2		7	(5)
	(240)	94	(190)	153
Total provision (benefit)	$ (151)	$ 87	$ (142)	$ 223

The effective income tax rate on the total benefit for the three and nine months ended September 30, 2010, is less than the federal statutory rate primarily due to the nondeductible goodwill impairment, partially offset by the impact of nontaxable noncontrolling interests. See Note 4 for a discussion of the goodwill impairment.

The effective income tax rate on the total provision for the three months ended September 30, 2009, is less than the federal statutory rate primarily due to taxes on foreign operations and the impact of nontaxable noncontrolling interests.

The effective income tax rate on the total provision for the nine months ended September 30, 2009, is greater than the federal statutory rate primarily due to the effect of state income taxes and the limitation of tax benefits associated with impairments of certain Venezuelan investments (see Note 4), partially offset by the impact of nontaxable noncontrolling interests.

For the next 12 months, we cannot predict with certainty whether we will achieve ultimate resolution of any uncertain tax position associated with our domestic or international operations that could result in increases or decreases of our unrecognized tax benefits. However, we believe there is a high degree of probability of an adjustment related to an international matter that could result in a decrease of approximately $17 million in our unrecognized tax benefits as early as the quarter ending December 31, 2010. Further, we have contested certain matters to the Internal Revenue Service (IRS) Appeals Division for which we have been in discussions with the IRS since 2006.

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Note 6. Earnings (Loss) Per Common Share from Continuing Operations

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Dollars in millions, except per-share amounts; shares in thousands)			
Income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders for basic and diluted earnings (loss) per common share (1)	$ (1,258)	$ 141	$ (1,266)	$ 266
Basic weighted-average shares	584,744	583,103	584,365	581,121
Effect of dilutive securities:				
Nonvested restricted stock units		2,544		1,911
Stock options		2,148		1,834
Convertible debentures		2,264		3,827
Diluted weighted-average shares	584,744	590,059	584,365	588,693
Earnings (loss) per common share from continuing operations:				
Basic	$ (2.15)	$ .24	$ (2.16)	$ .45
Diluted	$ (2.15)	$ .24	$ (2.16)	$ .45

(1) The three- and nine-month periods ended September 30, 2009, include $0.2 million and $1.0 million, respectively, of interest expense, net of tax, associated with our convertible debentures. This amount has been added back to *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to*

common stockholders to calculate diluted earnings per common share.

For the three and nine months ended September 30, 2010, 2.9 million and 3.0 million, respectively, weighted-average nonvested restricted stock units and 2.4 million and 2.9 million, respectively, weighted-average stock options have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to The Williams Companies, Inc.

Additionally, for both the three and nine months ended September 30, 2010, 2.2 million weighted-average shares related to the assumed conversion of our convertible debentures, as well as the related interest, net of tax, have been excluded from the computation of diluted earnings per common share. Inclusion of these shares would have an antidilutive effect on the diluted earnings per common share. We estimate that if *income (loss) from continuing operations attributable to The Williams Companies, Inc. available to common stockholders* was $54 million and $163 million of income for the three and nine months ended September 30, 2010, respectively, then these shares would become dilutive.

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, 2010		September 30, 2009	
Options excluded (millions)	6.9		6.1	
Weighted-average exercise price of options excluded	$24.54		$25.99	
Exercise price ranges of options excluded	$19.29	$40.51	$17.10	$42.29
Third quarter weighted-average market price	$19.14		$16.73	

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Notes (Continued)

Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)			
Components of net periodic pension expense:				
Service cost	$ 8	$ 8	$ 26	$ 24
Interest cost	16	16	48	47
Expected return on plan assets	(18)	(16)	(53)	(46)
Amortization of prior service cost	1		1	1
Amortization of net actuarial loss	9	11	26	32
Amortization of regulatory asset		1		1
Net periodic pension expense	$ 16	$ 20	$ 48	$ 59

	Other Postretirement Benefits			
	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)			
Components of net periodic other postretirement benefit expense:				
Service cost	$ 1	$	$ 2	$ 1
Interest cost	3	4	11	12
Expected return on plan assets	(2)	(2)	(7)	(6)
Amortization of prior service credit	(4)	(3)	(11)	(8)
Amortization of net actuarial loss	1	1	2	2
Amortization of regulatory asset		2	1	4
Net periodic other postretirement benefit expense (income)	$ (1)	$ 2	$ (2)	$ 5

During the nine months ended September 30, 2010, we contributed $61 million to our pension plans and $12 million to our other postretirement benefit plans. We presently do not anticipate making any additional contributions to our pension plans in the remainder of 2010. We presently anticipate making additional contributions of approximately $4 million to our other postretirement benefit plans in the remainder of 2010.

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Notes (Continued)

Note 8. Inventories

	September 30, 2010	December 31, 2009
	(Millions)	
Natural gas liquids and olefins	$ 72	$ 70
Natural gas in underground storage	70	47
Materials, supplies, and other	128	105
	$ 270	$ 222

Note 9. Debt and Banking Arrangements

Credit Facilities

At September 30, 2010, no loans are outstanding under our credit facilities. Letters of credit issued are:

	Expiration	Letters of Credit at September 30, 2010 (Millions)
$700 million unsecured credit facilities	October 1, 2010	$
$900 million unsecured credit facility	May 1, 2012	73
$1.75 billion Williams Partners L.P. unsecured credit facility	February 17, 2013	
Bilateral bank agreements		50
		$ 123

As part of our strategic restructuring (see Note 2), WPZ entered into a new $1.75 billion three-year senior unsecured revolving credit facility with Transco and Northwest Pipeline as co-borrowers. This credit facility replaced an unsecured $450 million credit facility, comprised of a $200 million revolving credit facility and a $250 million term loan which was terminated as part of the restructuring. At the closing, WPZ utilized $250 million of the credit facility to repay the outstanding term loan. During the third quarter of 2010, WPZ had a maximum of $430 million outstanding under this credit facility, which was primarily used to purchase an additional ownership interest in Overland Pass Pipeline Company LLC (OPPL). In September 2010, this outstanding balance was reduced to zero, primarily with proceeds from a WPZ equity offering. (See Note 2.)

The credit facility may, under certain conditions, be increased by up to an additional $250 million. The full amount of the credit facility is available to WPZ to the extent not otherwise utilized by Transco and Northwest Pipeline. Transco and Northwest Pipeline each have access to borrow up to $400 million under the credit facility to the extent not otherwise utilized by other co-borrowers. Each time funds are borrowed, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A s adjusted base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. WPZ is required to pay a commitment fee (currently 0.5 percent) based on the unused portion of the credit facility. The applicable margin and the commitment fee are based on the specific borrower s senior unsecured long-term debt ratings. The credit facility contains various covenants that limit, among other things, a borrower s and its respective subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, and allow any material change in the nature of its business. Significant financial covenants under the credit facility include:

WPZ ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 5 to 1.

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 55 percent for Transco and Northwest Pipeline.

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Notes (Continued)

Each of the above ratios are tested at the end of each fiscal quarter, and the debt to EBITDA ratio is measured on a rolling four-quarter basis (with the first full year measured on an annualized basis). At September 30, 2010, we are in compliance with these financial covenants.

The credit facility includes customary events of default. If an event of default with respect to a borrower occurs under the credit facility, the lenders will be able to terminate the commitments for all borrowers and accelerate the maturity of any loans of the defaulting borrower under the credit facility and exercise other rights and remedies.

As WPZ will be funding projects for its midstream and gas pipeline businesses, we reduced our $1.5 billion unsecured credit facility that expires May 1, 2012, to $900 million and removed Transco and Northwest Pipeline as borrowers.

In third-quarter 2010, there were no changes to our $700 million unsecured credit facilities, which expired on October 1, 2010, or to our unsecured credit facility used to facilitate our natural gas production hedging, which was due to expire in December 2013. In July 2010, the term of this facility expiring in December 2013 was extended to December 2015.

The impairments of goodwill and capitalized costs of certain producing properties and acquired unproved reserves recorded by our Exploration & Production segment in the third quarter of 2010 (see Note 4 and Note 10) will not impact our compliance with our $900 million unsecured credit facility or our ability to utilize Exploration & Production s credit agreement to facilitate hedging our future natural gas production.

Issuances and Retirements

In connection with the restructuring, WPZ issued $3.5 billion face value of senior unsecured notes as follows:

	(Millions)
3.80% Senior Notes due 2015	$ 750
5.25% Senior Notes due 2020	1,500
6.30% Senior Notes due 2040	1,250
Total	$ 3,500

Prior to the issuance of this debt, WPZ entered into forward starting interest rate swaps to hedge against variability in interest rates on a portion of the anticipated debt issuance. Upon the issuance of the debt, these instruments were terminated, which resulted in a payment of $7 million. This amount has been recorded in *accumulated other comprehensive income (loss)* (AOCI) and is being amortized over the term of the related debt.

As part of the issuance of the $3.5 billion unsecured notes, WPZ entered into registration rights agreements with the initial purchasers of the notes. An offer to exchange these unregistered notes for substantially identical new notes that are registered under the Securities Act of 1933, as amended, was commenced in June 2010 and completed in July 2010.

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Notes (Continued)

With the debt proceeds discussed above, we retired $3 billion of debt and paid $574 million in related premiums. The $3 billion of aggregate principal corporate debt retired includes:

	(Millions)
7.125% Notes due 2011	$ 429
8.125% Notes due 2012	602
7.625% Notes due 2019	668
8.75% Senior Notes due 2020	586
7.875% Notes due 2021	179
7.70% Debentures due 2027	98
7.50% Debentures due 2031	163
7.75% Notes due 2031	111
8.75% Notes due 2032	164
Total	$ 3,000

As a result of the changes in debt noted above, the weighted-average interest rate for unsecured fixed rate notes decreased from 7.7 percent at December 31, 2009 to 6.6 percent at September 30, 2010.

Note 10. Fair Value Measurements

Fair value is the amount 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 we believe 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.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving 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 for identical assets or liabilities in active markets 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 measurements primarily consist of financial instruments that are exchange traded.

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 measurements primarily consist of over-the-counter (OTC) instruments such as forwards, swaps, and options.

Level 3 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 measurements consist of instruments that are valued utilizing unobservable pricing inputs that are significant to the overall fair value.

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

Notes (Continued)

the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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

	September 30, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
Energy derivatives	$ 147	$ 672	$ 3	$ 822	$ 178	$ 911	$ 5	$ 1,094
ARO Trust Investments (see Note 11)	37			37	22			22
Total assets	$ 184	$ 672	$ 3	$ 859	$ 200	$ 911	$ 5	$ 1,116
Liabilities:								
Energy derivatives	$ 132	$ 274	$ 2	$ 408	$ 177	$ 826	$ 3	$ 1,006
Total liabilities	$ 132	$ 274	$ 2	$ 408	$ 177	$ 826	$ 3	$ 1,006

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures, swaps, 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 for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

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.

Forward, swap, and option contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. Significant inputs into our Level 2 valuations include commodity prices, implied volatility by location, and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. 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.

Our derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio is relatively short with more than 99 percent of the value of our derivatives portfolio expiring in the next 36 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

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Certain instruments trade in less active markets with lower availability of pricing information. These instruments are valued with a present value technique 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 instruments included in Level 3 at September 30, 2010, consist of NGL swaps and forward contracts for our midstream businesses, including those in our Williams Partners segment, as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment.

Reclassifications of fair value between Level 1, Level 2, and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers in or out of Level 1 and Level 2 occurred during the period ended September 30, 2010. During the third quarter of 2009, certain Exploration & Production options which hedge future sales of production were transferred from Level 3 to Level 2. These options were originally included in Level 3 because a significant input to the model, implied volatility by location, was considered unobservable. Due to increased transparency, this input was considered observable, and we transferred these options to Level 2.

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

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended September 30,			
	2010		2009	
	Net Energy Derivatives	Other Assets	Net Energy Derivatives	Other Assets
	(Millions)			
Beginning balance	$ 14	$	$ 413	$
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	7		161	
Included in other comprehensive income (loss)	(14)		(233)	
Purchases, issuances, and settlements	(6)		(163)	
Transfers into Level 3				
Transfers out of Level 3			(173)	
Ending balance	$ 1	$	$ 5	$
Unrealized gains (losses) included in income (loss) from continuing operations relating to instruments still held at September 30	$ 1	$	$ (1)	$

	Nine months ended September 30,			
	2010		2009	
	Net Energy Derivatives	Other Assets	Net Energy Derivatives	Other Assets
	(Millions)			
Beginning balance	$ 2	$	$ 507	$ 7
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	6		480	
Included in other comprehensive income (loss)	1		(329)	
Purchases, issuances, and settlements	(8)		(480)	(7)

Transfers into Level 3								
Transfers out of Level 3						(173)		
Ending balance	$	1	$		$	5	$	
Unrealized gains (losses) included in income (loss) from continuing operations relating to instruments still held at September 30	$	1	$		$	2	$	

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Notes (Continued)

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

The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Total losses for three months ended September 30,		**Total losses for nine months ended September 30,**	
	2010	**2009**	**2010**	**2009**
	(Millions)		**(Millions)**	
Impairments:				
Goodwill Exploration & Production	$ 1,003	$	$ 1,003 (a)	
Producing properties and acquired unproved reserves Exploration & Production	678		678 (b)	
Venezuelan property Discontinued Operations				211 (c)
Investment in Accroven Other				75 (d)
Cost-based investment Exploration & Production				11 (e)
	$ 1,681	$	$ 1,681	$ 297

(a) Due to a significant decline in forward natural gas prices across all future production periods as of September 30, 2010, we performed an interim impairment assessment of the approximate $1 billion of goodwill at Exploration & Production related to its domestic natural gas production operations (the reporting unit). Forward natural gas prices through 2025 as of September 30, 2010, used in our analysis declined more than 22 percent on average compared to the forward prices as of December 31, 2009. We estimated the fair value of the reporting unit on a stand-alone basis by valuing proved and unproved reserves, as well as estimating the fair values of other assets and liabilities which are identified to the reporting unit. We used an income approach (discounted cash flow) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves included reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions in valuing proved reserves included reserves quantities of more than 4.4 trillion cubic feet of gas equivalent; forward prices averaging approximately $4.65 per thousand cubic feet of gas equivalent (Mcfe) for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent. Unproved reserves (probable and possible) were valued using similar assumptions adjusted further for the uncertainty associated with these reserves by using after-tax discount rates of 13 percent and 15 percent, respectively, commensurate with our estimate of the risk of those reserves. In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its fair value. We then determined that the implied fair value of the goodwill was zero. As a result of our analysis, we recognized a full $1 billion impairment charge related to this goodwill.

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Notes (Continued)

(b) As of September 30, 2010, we assessed the carrying value of Exploration & Production s natural gas-producing properties and costs of acquired unproved reserves, for impairments as a result of recent significant declines in forward natural gas prices. Our assessment utilizes estimates of future cash flows. Significant judgments and assumptions in these assessments are similar to those used in the goodwill evaluation and include estimates of natural gas reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010, identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recorded a $678 million impairment charge in third-quarter 2010 as further described below. Fair value measured for these properties at September 30, 2010, was estimated to be approximately $320 million.

$503 million of the impairment charge related to natural gas-producing properties in the Barnett Shale. Significant assumptions in valuing these properties included proved reserves quantities of more than 227 billion cubic feet of gas equivalent, forward prices averaging approximately $4.67 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil; and an after-tax discount rate of 11 percent.

$175 million of the impairment charge related to acquired unproved reserves in the Piceance Highlands acquired in 2008. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent.

(c) Fair value measured at March 31, 2009, was $106 million. This value was based on our estimates of probability-weighted discounted cash flows that considered (1) the continued operation of the assets considering different scenarios of outcome, (2) the purchase of the assets by PDVSA, (3) the results of arbitration with varying degrees of award and collection, and (4) an after-tax discount rate of 20 percent.

(d) Fair value measured at March 31, 2009, was zero. This value was determined based on a probability-weighted discounted cash flow analysis that considered the deteriorating circumstances in Venezuela.

(e) Fair value measured at March 31, 2009, was zero. This value was based on an other-than-temporary decline in the value of our investment considering the deteriorating financial condition of a Venezuelan corporation in which Exploration & Production has a 4 percent interest.

Note 11. Financial Instruments, Derivatives, Guarantees and Concentration of Credit Risk

Financial Instruments

Fair-value methods

We use the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and cash equivalents and restricted cash: The carrying amounts reported in the Consolidated Balance Sheet approximate fair value due to the short-term maturity of these instruments. Current and noncurrent restricted cash is included in *other current assets and deferred charges* and *other assets and deferred charges*, respectively, in the Consolidated Balance Sheet.

ARO Trust Investments: Our Transco subsidiary deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust specifically designated to fund future asset retirement obligations (ARO Trust). The ARO Trust invests in a portfolio of mutual funds that are reported at fair value in *other assets and deferred charges* in the Consolidated Balance Sheet and are classified as available-for-sale. However, both realized and unrealized gains and losses are ultimately recorded as regulatory assets or liabilities.

Long-term debt: The fair value of our publicly traded long-term debt is determined using indicative period-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings. At September 30, 2010 and December 31, 2009, approximately 100 percent and

Notes (Continued)

97 percent, respectively, of our long-term debt was publicly traded. (See Note 9.)

Guarantees: The *guarantees* represented in the following table consist primarily of guarantees we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on certain lease performance obligations. To estimate the fair value of the guarantees, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate for each guarantee based on the credit rating of WilTel s current owner and the term of the underlying obligation. The default rates are published by Moody s Investors Service. Guarantees, if recognized, are included in *accrued liabilities* in the Consolidated Balance Sheet.

Other: Includes current and noncurrent notes receivable, margin deposits, customer margin deposits payable, and cost-based investments.

Energy derivatives: Energy derivatives include futures, forwards, swaps, and options. These are carried at fair value in the Consolidated Balance Sheet. See Note 10 for discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Asset (Liability)				
Cash and cash equivalents	$ 1,015	$ 1,015	$ 1,867	$ 1,867
Restricted cash (current and noncurrent)	$ 28	$ 28	$ 28	$ 28
ARO Trust Investments	$ 37	$ 37	$ 22	$ 22
Long-term debt, including current portion (a)	$(8,505)	$(9,681)	$(8,273)	$(9,142)
Guarantees	$ (35)	$ (34)	$ (36)	$ (33)
Other	$ (29)	$ (31)(b)	$ (23)	$ (25)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 417	$ 417	$ 178	$ 178
Other energy derivatives	$ (3)	$ (3)	$ (90)	$ (90)

(a) Excludes capital leases.

(b) Excludes certain cost-based investments in companies that are not publicly traded and therefore it is not practicable to estimate fair value. The carrying value of these investments was $2 million at September 30, 2010 and

December 31,
2009.

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We manage this risk on an enterprise basis and may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases and sales of natural gas and NGLs attributable to commodity price risk. Certain of these derivatives utilized for risk management purposes have been designated as cash flow hedges, while other derivatives have not been designated as cash flow hedges or do not qualify for hedge accounting despite hedging our future cash flows on an economic basis.

We produce, buy, and sell natural gas at different locations throughout the United States. We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in revenues or margins from fluctuations in natural gas market prices, we enter into natural gas futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However,

Notes (Continued)
ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item. Our financial option contracts are either purchased options or a combination of options that comprise a net purchased option or a zero-cost collar. Our designation of the hedging relationship and method of assessing effectiveness for these option contracts are generally such that the hedging relationship is considered perfectly effective and no ineffectiveness is recognized in earnings. Hedges for storage contracts have not been designated as cash flow hedges, despite economically hedging the expected cash flows generated by those agreements.

We produce and sell NGLs and olefins at different locations throughout North America. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs and olefins. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas and NGL market prices, we may enter into NGL or natural gas swap agreements, financial forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas and NGLs. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Other activities

We also enter into energy commodity derivatives for other than risk management purposes, including managing certain remaining legacy natural gas contracts and positions from our former power business and providing services to third parties. These legacy natural gas contracts include substantially offsetting positions and have an insignificant net impact on earnings.

Volumes

Our energy commodity derivatives are comprised of both contracts to purchase the commodity (long positions) and contracts to sell the commodity (short positions). Derivative transactions are categorized into four types:

Fixed price: Includes physical and financial derivative transactions that settle at a fixed location price;

Basis: Includes financial derivative transactions priced off the difference in value between a commodity at two specific delivery points;

Index: Includes physical derivative transactions at an unknown future price;

Options: Includes all fixed price options or combination of options (collars) that set a floor and/or ceiling for the transaction price of a commodity.

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of September 30, 2010. Natural gas is presented in millions of British Thermal Units (MMBtu), and NGLs are presented in gallons. The volumes for options represent at location zero-cost collars and present one side of the short position. The net index position for Exploration & Production includes certain positions on behalf of other segments.

Derivative Notional Volumes		**Meas.**	**Fixed Price**	**Basis**	**Index**	**Options**
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(155,285,000)	(154,865,000)		(147,295,000)
Williams Partners	Risk Management	MMBtu	6,365,000	4,305,000		
Williams Partners	Risk Management	Gallons	(69,636,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(10,342,499)	(11,040,000)	(11,577,007)	
Williams Partners	Risk Management	Gallons	(3,360,000)			

Other	Risk Management	Gallons	5,250,000	
Exploration & Production	Other	MMBtu	(402,000)	(13,532,000)

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Notes (Continued)

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheet as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	September 30, 2010		December 31, 2009	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Designated as hedging instruments	$ 454	$ 37	$ 352	$ 174
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	219	224	505	526
All other	149	147	237	306
Total derivatives not designated as hedging instruments	368	371	742	832
Total derivatives	$ 822	$ 408	$ 1,094	$ 1,006

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in AOCI or revenues.

	Three months ended September 30,		Nine months ended September 30,		
	2010	2009	2010	2009	Classification
	(Millions)		(Millions)		
Net gain (loss) recognized in other comprehensive income (effective portion)	$214	$ (91)	$524	$180	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$110	$176	$235	$506	Revenues
Gain (loss) recognized in income (ineffective portion)	$ 1	$ (1)	$ 4	$ 1	Revenues

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness or as a result of reclassifications to earnings following the discontinuance of any cash flow hedges.

The following table presents pre-tax gains and losses for our energy commodity derivatives not designated as hedging instruments.

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	

Revenues	$	26	$	8	$	37	$	28
Costs and operating expenses		11		13		18		27
Net gain (loss)	$	15	$	(5)	$	19	$	1

The cash flow impact of our derivative activities is presented in the Consolidated Statement of Cash Flows as *changes in current and noncurrent derivative assets and liabilities*.

Notes (Continued)

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, in certain circumstances, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor s and/or Moody s Investors Service. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability. Additionally, Exploration & Production has an unsecured credit agreement with certain banks related to hedging activities. We are not required to provide collateral support for net derivative liability positions under the credit agreement as long as the value of Exploration & Production s domestic natural gas reserves, as determined under the provisions of the agreement, exceeds by a specified amount certain of its obligations including any outstanding debt and the aggregate out-of-the-money position on hedges entered into under the credit agreement.

As of September 30, 2010, we have collateral totaling $42 million, all of which is in the form of letters of credit, posted to derivative counterparties to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $76 million, which includes a reduction of $1 million to our liability balance for our own nonperformance risk. At December 31, 2009, we had collateral totaling $96 million posted to derivative counterparties, all of which was in the form of letters of credit, to support the aggregate fair value of our net derivative liability position (reflecting master netting arrangements in place with certain counterparties) of $167 million, which included a reduction of $3 million to our liability balance for our own nonperformance risk. The additional collateral that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered, was $35 million and $74 million at September 30, 2010 and December 31, 2009, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in other comprehensive income and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. As of September 30, 2010, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to three years. Based on recorded values at September 30, 2010, $199 million of net gains (net of income tax provision of $120 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of September 30, 2010. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized within the next year will likely differ from these values. These gains or losses are expected to substantially offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

Guarantees

In addition to the guarantees and payment obligations discussed in Note 12, we have issued guarantees and other similar arrangements as discussed below.

We are required by our revolving credit agreements to indemnify lenders for any taxes required to be withheld from payments due to the lenders and for any tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. 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 and have no current expectation of a future claim.

Notes (Continued)

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $39 million at September 30, 2010. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees included in *accrued liabilities* on the Consolidated Balance Sheet is $35 million at September 30, 2010.

At September 30, 2010, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have a material adverse effect on our results of operations.

Concentration of Credit Risk

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements, and guarantees of payment by credit worthy parties. The gross credit exposure from our derivative contracts as of September 30, 2010, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 13	$ 15
Energy marketers and traders		140
Financial institutions	667	667
	$ 680	822
Credit reserves		
Gross credit exposure from derivatives		$ 822

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of September 30, 2010, excluding collateral support discussed below, is summarized as follows.

Counterparty Type	Investment Grade(a)	Total
	(Millions)	
Gas and electric utilities	$ 6	$ 8
Energy marketers and traders		1
Financial institutions	481	481
	$ 487	490
Credit reserves		

Net credit exposure from derivatives	$ 490

(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.

Notes (Continued)

Our nine largest net counterparty positions represent approximately 97 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are seven counterparty positions, representing 83 percent of our net credit exposure from derivatives, associated with Exploration & Production s hedging facility. Under certain conditions, the terms of this credit agreement may require the participating financial institutions to deliver collateral support to a designated collateral agent (which is another participating financial institution in the agreement). The level of collateral support required is dependent on whether the net position of the counterparty financial institution exceeds specified thresholds. The thresholds may be subject to prescribed reductions based on changes in the credit rating of the counterparty financial institution.

At September 30, 2010, the designated collateral agent holds $74 million of collateral support on our behalf under Exploration & Production s hedging facility. In addition, we hold collateral support, which may include cash or letters of credit, of $26 million related to our other derivative positions.

Note 12. Contingent Liabilities

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 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. The FERC has directed the parties to provide additional information on certain issues remanded by the U.S. Supreme Court, but delayed the submission of this information to permit the parties to explore possible settlements of the contractual disputes. The parties to the remanded proceeding have engaged the FERC s Dispute Resolution Service to assist with settlement discussions.

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 a significant portion of 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 will be used towards satisfying 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. Collection of the interest and the payment of interest on refund amounts from the escrow accounts are 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. Despite two FERC decisions that will affect the refund calculation, significant aspects of the refund calculation process remain unsettled, and the final refund calculation has not been made. Because of our settlements, we do not expect that the final resolution of refund obligations will have a material impact on us.

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Notes (Continued)

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 class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states.

The federal court in Nevada currently presides over cases that were transferred to it from state courts in Colorado, Kansas, Missouri, and Wisconsin. In 2008, the federal court in Nevada granted summary judgment in the Colorado case in favor of us and most of the other defendants, and on January 8, 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal. We expect that the Colorado plaintiffs will appeal, but the appeal cannot occur until the case against the remaining defendant is concluded.

On April 23, 2010, the Tennessee Supreme Court reversed the state appellate court and dismissed the plaintiffs claims against us on federal preemption grounds. The plaintiffs did not appeal this ruling to the United States Supreme Court. This case is now concluded in our favor.

On September 24, 2010, the Missouri Supreme Court declined to hear the plaintiff s appeal of the trial court s dismissal of a case for lack of standing. The case is now concluded in our favor.

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, 2010, we had accrued liabilities of $4 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. Currently, Northwest Pipeline is conducting additional assessments and remediation activities for mercury and other constituents at certain sites to comply with Washington s current environmental standards. At September 30, 2010, 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 new air quality standards for ground level ozone. In September 2009, the EPA announced that it would reconsider those standards. In January 2010, the EPA proposed more stringent standards, which are expected to be final in the fourth quarter 2010. The EPA expects that new eight-hour ozone nonattainment

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Notes (Continued)

areas will be designated in July 2011. The new standards and nonattainment areas will likely impact our operations, causing us to incur additional capital expenditures to comply. At this time we are unable to estimate the cost that may be required to meet these regulations. We expect that costs associated with these compliance efforts for our interstate gas pipelines will be recoverable through their rates.

In February 2010, the EPA promulgated a final rule establishing a new one-hour nitrogen dioxide (NO_2) National Ambient Air Quality Standard. The effective date of the new NO_2 standard was April 12, 2010. This new standard is subject to numerous challenges in federal court. We are unable at this time to estimate the cost of additions that may be required to meet this new regulation.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At September 30, 2010, we have accrued liabilities totaling $6 million for these costs.

In April 2010, we entered into a global settlement with the New Mexico Environmental Department s Air Quality Bureau (NMED) to resolve allegations of various air emissions violations at certain of our facilities. The settlement resolves notices of violation (NOVs) dating back to 2007 and includes a $400,000 penalty, as well as environmental projects totaling $1.35 million.

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. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, we submitted the requested information. On August 20, 2010, the EPA requested and our Transco subsidiary provided, similar information for a compressor station in Maryland.

In January 2010, the Colorado Department of Public Health and Environment (CDPHE) proposed a penalty against Williams Production RMT Company for alleged permit violations at four compressor stations in Colorado. A settlement was reached with the CDPHE in March 2010 wherein we paid a penalty of $96,750.

In July 2010, Williams Production RMT Company and the Colorado Oil and Gas Commission (COGCC) reached an agreement on the terms of an Administrative Order in Consent (AOC) addressing a release of hydrocarbons from a production pit in Garfield County, Colorado. That AOC includes a $423,300 penalty.

Former operations, including operations classified as discontinued

We have potential obligations in connection with assets and businesses we no longer operate. These potential obligations include the indemnification of the purchasers of certain of these assets and businesses for environmental and other liabilities existing at the time the sale was consummated. Our responsibilities include those described below.

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

At September 30, 2010, we have accrued environmental liabilities of $29 million related to these matters.

Notes (Continued)

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

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but any incremental amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, 14 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 subsidiaries within our midstream business. All remaining defendants opposed class certification and on September 18, 2009, the court denied plaintiffs most recent motion to certify the class. On October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. On March 31, 2010, the court entered an order denying plaintiffs motion for reconsideration and as a result, there are no class action allegations remaining in the case.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay (a joint venture between Gulsby and Bay Ltd.) for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we recorded a charge based on our estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $20 million. 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, Bay Ltd., and NAICO appealed the judgment. In February 2009, we settled with certain of these parties and reduced our liability as of December 31, 2008, by $43 million, including $11 million of interest. If the judgment is upheld on appeal, our remaining liability will be substantially less than the amount of our accrual for these matters.

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. We reached a final partial settlement agreement

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Notes (Continued)

for an amount that was previously accrued. We received a favorable ruling on our motion for summary judgment on one claim now on appeal by plaintiffs. We do not anticipate trial on the other remaining issue related to royalty payment calculation and obligations under specific lease provisions before 2011. While we are not able to estimate the amount of any additional exposure at this time, it is reasonably possible that plaintiff s claims could reach a material amount.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions used in the calculation of royalties. Although we are not a party to these matters, we have monitored them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. One of these matters involving federal litigation was decided on October 5, 2009. The resolution of this specific matter is not material to us. However, other related issues in these matters that could be material to us remain outstanding.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At September 30, 2010, 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 liquidity or financial position.

Note 13. Segment Disclosures

In February 2010, we completed our strategic restructuring that resulted in a revision to our segment reporting structure. Beginning with first-quarter 2010 reporting, our reportable segments are Williams Partners, Exploration & Production, and Other. (See Note 2.)

Our segment presentation of Williams Partners is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions associated with this master limited partnership structure. Following our restructuring, this entity maintains a capital and cash management structure that is separate from ours. Williams Partners is expected to be self-funding and maintains its own lines of bank credit and cash management accounts. These factors, coupled with a different cost of capital from our other businesses, serve to differentiate the management of this entity as a whole.

Performance Measurement

We currently evaluate segment operating performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *equity earnings*

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Notes (Continued)

(losses) and *income (loss) from investments*. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

The primary types of costs and operating expenses by segment can be generally summarized as follows:

Williams Partners commodity purchases (primarily for NGL and crude marketing, shrink and fuel), depreciation and operation and maintenance expenses;

Exploration & Production commodity purchases (primarily in support of commodity marketing and risk management activities), depletion, depreciation and amortization, lease and facility operating expenses and operating taxes;

Other commodity purchases (primarily for shrink, feedstock and NGL and olefin marketing activities), depreciation and operation and maintenance expenses.

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Notes (Continued)

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

	Williams Partners	Exploration & Production	Other	Eliminations	Total
			(Millions)		
Three months ended September 30, 2010					
Segment revenues:					
External	$ 1,232	$ 841	$ 231	$	$ 2,304
Internal	59	171	7	(237)	
Total revenues	$ 1,291	$ 1,012	$ 238	$ (237)	$ 2,304
Segment profit (loss)	$ 343	$ (1,603)	$ 80	$	$ (1,180)
Less:					
Equity earnings	24	5	9		38
Income from investments			30		30
Segment operating income (loss)	$ 319	$ (1,608)	$ 41	$	(1,248)
General corporate expenses					(43)
Total operating loss					$ (1,291)
Three months ended September 30, 2009*					
Segment revenues:					
External	$ 1,133	$ 752	$ 213	$	$ 2,098
Internal	48	127	9	(184)	
Total revenues	$ 1,181	$ 879	$ 222	$ (184)	$ 2,098
Segment profit	$ 347	$ 100	$ 31	$	$ 478
Less equity earnings	30	4	10		44
Segment operating income	$ 317	$ 96	$ 21	$	434
General corporate expenses					(40)
Total operating income					$ 394

	Williams Partners	Exploration & Production	Other	Eliminations	Total
			(Millions)		

Nine months ended September 30, 2010										
Segment revenues:										
External	$ 3,925	$	2,511	$	756	$			$ 7,192	
Internal	191		579		22		(792)			
Total revenues	$ 4,116	$	3,090	$	778	$	(792)		$ 7,192	
Segment profit (loss)	$ 1,103	$	(1,354)	$	186	$		$	(65)	
Less:										
Equity earnings	77		15		25				117	
Income from investments					43				43	
Segment operating income (loss)	$ 1,026	$	(1,369)	$	118	$			(225)	
General corporate expenses									(173)	
Total operating loss								$	(398)	
Nine months ended September 30, 2009*										
Segment revenues:										
External	$ 3,099	$	2,301	$	529	$			$ 5,929	
Internal	120		363		21		(504)			
Total revenues	$ 3,219	$	2,664	$	550	$	(504)		$ 5,929	
Segment profit (loss)	$ 884	$	290	$	(13)	$			$ 1,161	
Less:										
Equity earnings	51		12		30				93	
Loss from investments					(75)				(75)	
Segment operating income	$ 833	$	278	$	32	$			1,143	
General corporate expenses									(118)	
Total operating income									$ 1,025	

* Recast as discussed in Note 2.

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Notes (Continued)

Total segment revenues for Exploration & Production include $435 million, $344 million, $1,357 million, and $1,031 million of gas management revenues for the three and nine months ended September 30, 2010 and 2009, respectively. Gas management revenues include sales of natural gas in conjunction with marketing services provided to third parties and intercompany sales of fuel and shrink gas to the midstream businesses in Williams Partners. These revenues are substantially offset by similar amounts of gas management costs.

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

	Total Assets	
	September 30, 2010	**December 31, 2009**
	(Millions)	
Williams Partners	$ 12,465	$ 11,981
Exploration & Production (1)	9,381	10,575
Other	3,972	4,193
Eliminations	(1,970)	(1,469)
Total	$ 23,848	$ 25,280

(1) The decrease in Exploration & Production s total assets is primarily due to impairments of goodwill, producing properties, and acquired unproved reserve costs. See Note 4 and Note 10.

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

Company Outlook

We believe we will continue to execute on our 2010 business plan and capture attractive growth opportunities. While the economic environment in the latter half of 2009 and first quarter of 2010 improved compared to conditions earlier in 2009, this trend has moderated in the second and third quarters of 2010 as global economies continue to struggle. Although recently natural gas prices have continued to decline as a result of continued weak demand coupled with increasing supply which contributed significantly to impairments recorded by our Exploration & Production segment in the third quarter of 2010, we continue to expect opportunities for growth across all of our businesses. However, if economic conditions and/or the energy commodity price environment decline, we could experience further negative impacts to future operating results and increased risk of nonperformance of counterparties or impairments of long-lived assets.

As a result of our 2010 restructuring (see Note 2 of Notes to Consolidated Financial Statements), we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

We continue to operate with a focus on EVA® and invest in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering and processing, interstate natural gas pipeline systems, and natural gas drilling;
- Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

Potential risks and/or obstacles that could impact the execution of our plan include:

- Lower than anticipated energy commodity prices;
- Lower than expected levels of cash flow from operations;
- Availability of capital;
- Counterparty credit and performance risk;
- Decreased drilling success at Exploration & Production;
- Decreased volumes from third parties served by our midstream businesses;
- General economic, financial markets, or industry downturn;
- Changes in the political and regulatory environments;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate insurance policy limit is $75 million in the event of a material loss.

We continue to address these risks through utilization of commodity hedging strategies, disciplined investment strategies, and maintaining at least $1 billion in consolidated liquidity from cash and cash equivalents and unused revolving credit facilities. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

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Management s Discussion and Analysis (Continued)

Overview of Nine Months Ended September 30, 2010

Income (loss) from continuing operations attributable to The Williams Companies, Inc., for the nine months ended September 30, 2010, changed unfavorably by $1,532 million compared to the nine months ended September 30, 2009. This change is reflective of:

$1,003 million full impairment charge related to goodwill at Exploration & Production and $678 million of pre-tax charges associated with impairments of certain producing properties and acquired unproved reserves at Exploration & Production during the third quarter of 2010 (See Note 4 and Note 10 of Notes to Consolidated Financial Statements.);

$648 million of pre-tax costs attributable to The Williams Companies, Inc., associated with our 2010 restructuring, including $606 million of early debt retirement costs.

Partially offsetting the increased costs are:

The improved energy commodity price environment in the first nine months of 2010 as compared to the first nine months of 2009;

The absence of a $75 million pre-tax impairment charge in the first quarter of 2009 related to our Venezuelan equity investment in Accroven SRL (Accroven). (See Note 4 of Notes to Consolidated Financial Statements.)

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the nine months ended September 30, 2010, increased $183 million compared to the nine months ended September 30, 2009, primarily due to the improvement in the energy commodity price environment in the first nine months of 2010 as compared to the first nine months of 2009. *(*See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Recent Events

On October 26, 2010, Williams Partners L.P. (WPZ) agreed to acquire certain gathering and processing assets in Colorado s Piceance basin, currently held by Exploration & Production, for $782 million. We expect the transaction to be completed during the fourth quarter of 2010. The agreement includes consideration of $702 million in cash, which WPZ expects to fund using its credit facility and/or debt, approximately 1.8 million common units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest.

On May 24, 2010, WPZ and Williams Pipeline Partners L.P. (WMZ), entered into a merger agreement providing for the merger of WMZ and WPZ. On August 31, 2010 the WMZ unitholders approved the proposed merger between the two master limited partnerships and the merger was completed. (See Note 2 of Notes to Consolidated Financial Statements.)

In July 2010, we notified our partner in the Overland Pass Pipeline Company LLC (OPPL) of our election to exercise our option to purchase an additional ownership interest, which provides us with a 50 percent ownership interest in OPPL, for approximately $424 million. This transaction was completed on September 9, 2010, primarily with proceeds from WPZ s credit facility. (See Results of Operations Segments, Williams Partners.) Additionally, during September 2010, WPZ completed an equity offering resulting in net proceeds of $380 million, which were used to reduce the borrowing under WPZ s credit facility. (See Note 2 of Notes to Consolidated Financial Statements.)

In May 2010, Exploration & Production announced a major acreage acquisition in the Marcellus Shale located in northeast Pennsylvania. In July 2010, the purchase was completed for $597 million, including closing adjustments. (See Results of Operations Segments, Exploration & Production.)

Management s Discussion and Analysis (Continued)

In February 2010, we completed a strategic restructuring that involved contributing certain of our wholly and partially owned subsidiaries to WPZ, our consolidated master limited partnership, and restructuring our debt. (See Notes 2 and 9 of Notes to Consolidated Financial Statements and Management s Discussion and Analysis of Financial Condition and Liquidity.)

In April 2010, our Board of Directors approved a regular quarterly dividend of $0.125 per share, which reflects an increase of 14 percent compared to the $0.11 per share that we paid in each of the eight prior quarters.

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 of this Form 10-Q and our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 26, 2010.

Fair Value Measurements

Certain of our energy derivative assets and energy derivative liabilities 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. At September 30, 2010, less than one percent of our energy derivative assets and energy derivative liabilities measured at fair value on a recurring basis are included in Level 3. 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 for our energy derivative assets and energy derivative liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At September 30, 2010, the credit reserve is less than $1 million on our net derivative assets and $1 million on our net derivative 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.

At September 30, 2010, 79 percent of the value of our derivatives portfolio expires in the next 12 months and more than 99 percent expires in the next 36 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at September 30, 2010, consist of natural gas liquids swaps and forward contracts for our midstream businesses, including those in our Williams Partners segment, as well as natural gas index transactions that are used to manage the physical requirements of our Exploration & Production segment. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

Exploration & Production has an unsecured credit agreement through December 2015 with certain banks that, so long as certain conditions are met, serves to reduce our usage of cash and other credit facilities for margin requirements related to instruments included in the facility.

For the nine months ended September 30, 2010 and 2009, we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they

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Management s Discussion and Analysis (Continued)

include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. (See Note 10 of Notes to Consolidated Financial Statements.)

Critical Accounting Estimate

Impairments of Goodwill and Long-Lived Assets

As disclosed in our annual consolidated financial statements and notes thereto in Exhibit 99.1 of our Form 8-K dated May 26, 2010, we assess goodwill for impairment annually as of the end of the year. We perform interim assessments of goodwill if impairment triggering events or circumstances are present. One such triggering event is a significant decline in forward natural gas prices. During the first and second quarter of 2010, we evaluated the impact of declines in forward gas prices across all future production periods and determined that the impact was not significant enough to warrant a full impairment review. Forward natural gas prices through 2025 used in these prior analyses had declined less than 10 percent, on average, from December 31, 2009 through March 31, 2010 and June 30, 2010. During the third quarter of 2010, these forward natural gas prices through 2025 declined an additional 19 percent for a total year-to-date decline of more than 22 percent on average through September 30, 2010. Based on forward prices as of September 30, 2010, we evaluated the impact of this decline across all future production periods and determined that a full impairment review was warranted.

As a result, we evaluated our goodwill of approximately $1 billion resulting from a 2001 acquisition at Exploration & Production related to its domestic natural gas production operations (the reporting unit). Our impairment evaluation of goodwill first considers our management s estimate of the fair value of the reporting unit compared to its carrying value, including goodwill. If the carrying value of the reporting unit exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess. Because quoted market prices are not available for the reporting unit, management applies reasonable judgments (including market supported assumptions when available) in estimating the fair value for the reporting unit. We estimate the fair value of the reporting unit on a stand-alone basis and also consider our market capitalization and third party estimates in corroborating our estimate of the fair value of the reporting unit.

The fair value of the reporting unit is estimated primarily by valuing proved and unproved reserves. We use an income approach (discounted cash flows) for valuing reserves. The significant inputs into the valuation of proved and unproved reserves include reserve quantities, forward natural gas prices, anticipated drilling and operating costs, anticipated production curves, income taxes, and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assume a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired.

In our assessment as of September 30, 2010, the carrying value of the reporting unit, including goodwill, exceeded its fair value. We then determined that the implied fair value of the goodwill was zero. As a result, we recognized a full $1 billion impairment charge related to this goodwill. See Note 4 and Note 10 of Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include the estimated fair value of the asset, undiscounted future cash flows, discounted future cash flows, and the current and future economic environment in which the asset is operated.

As a result of significant declines in forward natural gas prices during the third quarter of 2010, we assessed Exploration & Production s natural gas producing properties and acquired unproved reserve costs, for impairment using estimates of future cash flows. Significant judgments and assumptions in these assessments include estimates of natural gas reserves quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, drilling plans, expected capital costs, and our estimate of an applicable discount rate commensurate with risk of the underlying cash flow estimates. The assessment performed at September 30, 2010 identified certain properties with a carrying value in excess of their calculated fair values. As a result, we recognized a $678 million impairment charge. See Note 4 and Note 10 of

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Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required. These reviews included Exploration & Production s other domestic producing properties and acquired unproved reserve costs, and utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. For Exploration & Production s other assets reviewed, but for which impairment charges were not recorded, we estimate that approximately 15 percent could be at risk for impairment if forward prices across all future periods decline by approximately 7 to 15 percent, on average, as compared to the forward prices at September 30, 2010. A substantial portion of the remaining carrying value of these other assets (primarily related to Exploration & Production s assets in the Piceance basin) could be at risk for impairment if forward prices across all future periods decline by at least 25 percent, on average, as compared to the prices at September 30, 2010.

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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, 2010, compared to the three and nine months ended September 30, 2009. 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,		$	%
	2010	2009	Change*	Change*	2010	2009	Change*	Change*
	(Millions)				(Millions)			
Revenues	$ 2,304	$ 2,098	+206	+10%	$ 7,192	$ 5,929	+1,263	+21%
Costs and expenses:								
Costs and operating expenses	1,752	1,537	-215	-14%	5,397	4,373	-1,024	-23%
Selling, general and administrative expenses	123	126	+3	+2%	356	380	+24	+6%
Impairments of goodwill and long-lived assets	1,681		-1,681	NM	1,681	5	-1,676	NM
Other (income) expense net	(4)	1	+5	NM	(17)	28	+45	NM
General corporate expenses	43	40	-3	-8%	173	118	-55	-47%
Total costs and expenses	3,595	1,704			7,590	4,904		
Operating income (loss)	(1,291)	394			(398)	1,025		
Interest accrued net	(145)	(153)	+8	+5%	(433)	(440)	+7	+2%
Investing income net	68	39	+29	+74%	162	2	+160	NM
Early debt retirement costs				0%	(606)		-606	NM
Other expense net	(4)	(1)	-3	NM	(12)	(2)	-10	NM
Income (loss) from continuing operations before income taxes	(1,372)	279			(1,287)	585		
Provision (benefit) for income taxes	(151)	87	+238	NM	(142)	223	+365	NM
Income (loss) from continuing operations	(1,221)	192			(1,145)	362		
Income (loss) from discontinued operations	(5)	2	-7	NM	(5)	(223)	+218	+98%
Net Income (loss)	(1,226)	194			(1,150)	139		
Less: Net income attributable to noncontrolling interests	37	51	+14	+27%	121	26	-95	NM

Net income (loss) attributable to The Williams Companies, Inc.	$ (1,263)	$ 143	$ (1,271)	$ 113

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

Three months ended September 30, 2010 vs. three months ended September 30, 2009

The increase in *revenues* is primarily due to higher gas management and production revenues, reflecting an increase in average natural gas prices, partially offset by a decrease in natural gas sales volumes associated with gas management activities at Exploration & Production. Additionally, natural gas liquids (NGL) and crude oil marketing revenues and NGL production revenues increased at Williams Partners, reflecting higher average NGL and crude prices. NGL and olefin production revenues at Other also increased due to higher average per-unit prices.

The increase in *costs and operating expenses* is primarily due to increased average natural gas prices associated with gas management activities, partially offset by a decrease in natural gas purchase volumes at Exploration & Production and increased NGL and crude oil marketing purchases and NGL production costs at Williams Partners, reflecting higher average NGL, crude and natural gas prices.

Impairments of goodwill and long-lived assets in 2010 includes a $1,003 million impairment of goodwill and $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration & Production.

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Management s Discussion and Analysis (Continued)

Other (income) expense net within *operating income (loss)* in 2010 includes $13 million of gains on the sales of certain assets at Exploration & Production.

The unfavorable change in *operating income (loss)* is primarily due to impairment charges in 2010 at Exploration & Production as previously discussed.

The increase in *investing income net* is primarily due to a $30 million gain in the third quarter of 2010 on the sale of our 50 percent interest in Accroven in the second quarter of 2010 (see Note 4 of Notes to Consolidated Financial Statements).

Provision (benefit) for income taxes changed favorably primarily due to the pre-tax loss in 2010 compared to pre-tax income in 2009. 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.

The favorable change in *net income attributable to noncontrolling interests* reflects lower results, primarily at WPZ, due to increased interest on debt in 2010 compared to 2009.

Nine months ended September 30, 2010 vs. nine months ended September 30, 2009

The increase in *revenues* is primarily due to higher NGL and crude oil marketing revenues and higher NGL production revenues at Williams Partners, reflecting higher average NGL and crude prices. Additionally, Exploration & Production gas management and production revenues increased reflecting an increase in average natural gas prices, partially offset by a decrease in production volumes sold. NGL and olefin production revenues at Other also increased due to higher average per-unit prices.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and NGL production costs at Williams Partners, reflecting higher average NGL, crude and natural gas prices. Exploration & Production costs increased primarily due to increased average natural gas prices associated with gas management activities and higher operating taxes. Additionally, NGL and olefin production costs at Other increased due to higher average per-unit feedstock costs.

Selling, general and administrative expenses decreased primarily due to lower pension and certain other employee-related expenses at Williams Partners.

Impairments of goodwill and long-lived assets in 2010 includes a $1,003 million impairment of goodwill and $678 million of impairments of certain producing properties and acquired unproved reserves at Exploration & Production.

The favorable change in *other (income) expense net* within *operating income (loss)* is primarily due to the absence of $32 million of penalties in 2009 from the early termination of certain drilling rig contracts at Exploration & Production, a $14 million increase in involuntary conversion gains at Williams Partners due to insurance recoveries that are in excess of the carrying value of assets and $13 million of gains in 2010 on the sales of certain assets at Exploration & Production.

General corporate expenses in 2010 includes $45 million of transaction costs associated with our strategic restructuring transaction.

The unfavorable change in *operating income (loss)* is primarily due to impairment charges in 2010 at Exploration & Production previously discussed and $45 million of transaction costs in 2010 associated with our strategic restructuring transaction, partially offset by the absence of $32 million of expenses in 2009 related to penalties from the early release of drilling rigs and $13 million of gains in 2010 on the sales of certain assets at Exploration & Production, a $14 million increase in involuntary conversion gains at Williams Partners and an improved energy commodity price environment in 2010 compared to 2009.

The increase in *investing income net* is primarily due to the absence of a $75 million impairment charge in 2009 and a $43 million gain on the sale of our 50 percent interest in Accroven in 2010 at Other, a $24 million

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increase in equity earnings, primarily at Williams Partners and the absence of an $11 million impairment charge in 2009 related to a cost-based investment at Exploration & Production.

Early debt retirement costs in 2010 reflect costs related to corporate debt retirements associated with our first quarter strategic restructuring transaction, including premiums of $574 million.

Provision (benefit) for income taxes changed favorably primarily due to the pre-tax loss in 2010 compared to pre-tax income in 2009. 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*.

The unfavorable change in *net income attributable to noncontrolling interests* reflects higher results, primarily at Williams Partners, due to an improved energy commodity price environment in 2010 compared to 2009 as well as the impact of the first-quarter 2009 impairments and related charges associated with our discontinued Venezuela operations.

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Williams Partners

Our Williams Partners segment reflects 100 percent of the segment profit of WPZ, our consolidated master limited partnership. WPZ includes two interstate natural gas pipelines, as well as investments in natural gas pipeline-related companies, which serve regions from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington and from the Gulf of Mexico to the northeastern United States. WPZ also includes natural gas gathering and processing and treating facilities and oil gathering and transportation facilities located primarily in the Rocky Mountain and Gulf Coast regions of the United States. We currently own approximately 77 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

Williams Partners ongoing strategy is to safely and reliably operate large-scale, interstate natural gas transmission and midstream infrastructures 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 and utilizing our low cost-of-capital to invest in growing markets, including the deepwater Gulf of Mexico, the Marcellus Shale, the western United States, and areas of increasing natural gas demand.

Overview of Nine Months Ended September 30, 2010

Significant events during 2010 include the following:

NGL Volumes

Our NGL equity sales volumes for the third quarter of 2010 were unfavorably impacted due to a number of temporary items, including lower gas deliveries in the Gulf of Mexico area due to disruptions in third-party production unrelated to the drilling moratorium, an isolated sub-sea mechanical issue that reduced other gas production flow in the Gulf area, the impact of a force majeure shut-down of a third-party fractionator which limited plant production deliveries into Overland Pass Pipeline and maintenance issues at our Echo Springs plant. These issues have all been resolved and production is currently flowing at normal levels. These unfavorable impacts are partially offset by a full quarter of production at Willow Creek, compared with start-up in 2009.

Perdido Norte

Our Perdido Norte project, in the western deepwater of the Gulf of Mexico, began start-up of operations late in the first quarter of 2010. The project includes a 200 million cubic feet per day (MMcf/d) expansion of our onshore Markham gas processing facility and a total of 184 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. Shortly after an initial startup, production was suspended by the operator of the deepwater producing platforms during the second quarter to address facility issues and the third quarter was impacted by further delays and a mechanical issue that reduced the Boomvang gas production flow below 2009 levels. These issues have been resolved and both oil and gas production are currently flowing.

Impact of Gulf Oil Spill

Our transportation and processing assets in the Gulf of Mexico were not significantly impacted by the Deepwater Horizon oil spill. Operations are normal at all facilities and we did not experience any operational or logistical issues that hindered the safety of our employees or facilities. The drilling moratorium, in force from May to October, in the Gulf of Mexico impacted our operations through production delays and is expected to reduce future volumes for the remainder of 2010 and more significantly in 2011. We estimate a $10 million unfavorable impact to segment profit in 2010. If impacted producers reduce their offshore or onshore capital growth plans, our expected future volumes will be reduced more significantly in the long term. While we continue to carefully monitor the events and business environment in the Gulf of Mexico for potential negative impacts, we also continue to pursue major expansion and growth opportunities in the Gulf of Mexico.

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Management s Discussion and Analysis (Continued)

Overland Pass Pipeline

In September 2010, we completed the $424 million acquisition of an additional 49 percent ownership interest in OPPL, which increased our ownership interest to 50 percent. In 2006, we entered into an agreement to develop new pipeline capacity for transporting NGLs from production areas in the Rocky Mountain area to central Kansas. Our partner reimbursed us for the development costs we had incurred for the proposed pipeline and acquired 99 percent of the pipeline. We retained a 1 percent interest and the option to increase our ownership to 50 percent within two years of the pipeline becoming operational in November of 2008. As long as we retain a 50 percent ownership interest in OPPL, we have the right to become operator. We have notified our partner of our intent to do so and are currently working on an early 2011 transition. Work is also under way to determine optimal expansions to serve producers in the OPPL corridor. OPPL includes a 760-mile NGL pipeline from Opal, Wyoming, to the Mid-Continent NGL market center in Conway, Kansas, along with 150- and 125-mile extensions into the Piceance and Denver-Joules Basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek facility in Colorado are dedicated for transport on OPPL under a long-term shipping agreement.

Volatile commodity prices

Average per-unit NGL margins in the nine months ending September 30, 2010, are significantly higher than the same period of 2009, benefiting from a period of increasing average NGL prices while abundant natural gas supplies limited the increase in natural gas prices. Benefits from favorable natural gas price differentials in the Rocky Mountain area have narrowed since the second quarter of 2009 such that our realized per-unit margins are only slightly greater than that of the industry benchmarks for natural gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

NGL margins are defined as NGL revenues less any applicable BTU replacement cost, plant fuel, and third-party transportation and fractionation. Per-unit NGL margins are calculated based on sales of our own equity volumes at the processing plants.

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Management s Discussion and Analysis (Continued)

Williams Pipeline Partners L.P.

During the third quarter, WPZ consummated its merger with WMZ. As a result, WMZ is wholly owned by WPZ and is no longer publicly traded.

Mobile Bay South expansion project

In May 2010, a compression facility in Alabama allowing natural gas pipeline transportation service to various southbound delivery points was placed into service. The cost of the project is estimated to be $32 million and increased capacity by 254 thousand dekatherms per day (Mdt/d).

Outlook for the Remainder of 2010

The following factors could impact our business in 2010.

Commodity price changes

While our per-unit NGL margins have declined from the first quarter of 2010, we expect our average per-unit NGL margins in 2010 to be higher than our average per-unit margins in 2009 and our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of crude oil, although NGL, crude and natural gas prices are highly volatile and difficult to predict. NGL margins are highly dependent upon continued demand within the global economy. However, NGL products are currently the preferred feedstock for ethylene and propylene production, which has been shifting away from the more expensive crude-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets.

As part of our efforts to manage commodity price risks on an enterprise basis, we continue to evaluate our commodity hedging strategies. To reduce the exposure to changes in market prices, we have entered into NGL swap agreements to fix the prices of approximately 25 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink gas requirements for the remainder of 2010. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $64 million.

Gathering, processing, and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. Our customers are generally large producers, and we have not experienced and do not anticipate an overall significant decline in volumes due to reduced drilling activity. However, if producers reduce their offshore or onshore capital growth plans, volumes will likely be reduced.

In our onshore businesses, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in 2010 compared to 2009 as our Willow Creek facility moves into a full year of operation, and our expansion at Echo Springs ramps up in the fourth quarter of 2010. The Four Corners area is the only area where we have experienced declining volumes due to reduced drilling activities and the declines have been moderate due to the mature wells that make up the Four Corners production.

We expect our Perdido Norte expansion operations to contribute new fee revenues, NGL volumes, depreciation expense, and operating expenses in the fourth quarter of 2010. However, due to the previously discussed delays in the Perdido start-up and volume disruptions, and to lower volumes in other Gulf of Mexico areas due to natural declines, we expect 2010 fee revenues, NGL volumes, depreciation expense and operating expenses in our Gulf businesses to be moderately unfavorable to 2009.

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Management s Discussion and Analysis (Continued)

Expansion projects

We expect to spend $1,860 million to $2,000 million in 2010 on capital projects and additional investments in partially owned equity investments, including our recently announced acquisition of Piceance basin gathering and processing assets currently held by Exploration & Production, of which $1,555 million to $1,695 million remains to be spent. The ongoing major expansion projects include:

85 North

An expansion of our existing natural gas transmission system from Alabama to various delivery points as far north as North Carolina. The cost of the project is estimated to be $240 million. Phase I service was placed into service in July 2010 and increased capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 219 Mdt/d.

Sundance Trail

A 16-mile, 30-inch natural gas pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost $56 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Echo Springs

Additional processing and NGL production capacities at our Echo Springs facility and related gathering system expansions in the Wamsutter area of Wyoming. Start-up operations of the fourth train at the Echo Springs facility are in process and we expect the additional capacity to be in service in the fourth quarter of 2010.

Mobile Bay South II

Additional compression facilities and modifications to existing facilities in Alabama allowing natural gas transportation service to various southbound delivery points. In July 2010 we received approval from the U.S. Federal Energy Regulatory Commission. Construction began in October 2010 and is estimated to cost $36 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Marcellus Shale

A 33-mile natural gas gathering pipeline in the Marcellus Shale region, which we will construct and operate in conjunction with a long-term agreement with a significant producer. In order to pursue future opportunities, the project has been increased from a 20-inch diameter to a 24-inch diameter pipeline. Construction on the pipeline, which will deliver gas into the Transco pipeline, is expected to begin in the first quarter of 2011 and be completed during 2011.

Laurel Mountain

Additional capital to be invested within our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment to enable the rapid expansion of our gathering system including the initial stages of projects that will ultimately provide over 1.5 Bcf/d of gathering capacity and 1,400 miles of gathering lines, including 400 new miles of 6-inch to 24-inch diameter pipeline. Construction has begun on our Shamrock compressor station with an initial capacity of 60 MMcf/d, expandable to 350 MMcf/d, which will likely be the largest central delivery point out of the Laurel Mountain system. Laurel Mountain will also benefit from a joint venture transaction between its anchor customer and a third-party drilling partner, which we expect to provide the funding to accelerate the customer s drilling plans and grow their leasehold position in the Marcellus Shale region dedicated to Laurel Mountain gathering services.

We have several other proposed projects to meet customer demands in addition to the various in-progress expansion projects previously discussed. Subject to regulatory approvals, construction of some of these projects could begin in the remainder of 2010.

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Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Segment revenues	$ 1,291	$ 1,181	$ 4,116	$ 3,219
Segment profit	$ 343	$ 347	$ 1,103	$ 884

Three months ended September 30, 2010 vs. three months ended September 30, 2009

The increase in *segment revenues* includes:

A $76 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.

$18 million higher natural gas transportation imbalance settlements (offset in *segment costs and expenses)* and higher transportation revenue from expansion projects placed in service.

A $12 million increase in revenues associated with the production of NGLs reflecting an increase of $43 million associated with a 23 percent increase in average NGL, primarily non-ethane, per-unit sales prices, partially offset by a decrease of $31 million associated with 14 percent lower equity sales volumes.

A $5 million decrease in fee revenues primarily due to reduced fees from lower deepwater gathering and transportation volumes, partially offset by new fees for processing natural gas production at Willow Creek.

The increase in s*egment costs and expenses* of $108 million includes:

A $77 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes more than offset similar changes in marketing revenues.

$18 million higher natural gas transportation imbalance settlements (offset in *segment revenues*).

An $18 million increase in costs associated with the production of NGLs due primarily to a 40 percent increase in average natural gas prices, partially offset by an 11 percent decrease in gas volumes for BTU replacement cost and plant fuel.

A $7 million favorable change related to involuntary conversion gains due to insurance recoveries in excess of the carrying value of our Gulf assets which were damaged by Hurricane Ike in 2008, partially offset by the absence of $5 million involuntary conversion gains in 2009 due to insurance recoveries in excess of the carrying value of our Ignacio plant, which was damaged by a fire in 2007.

The decrease in William Partners *segment profit* includes:

$6 million of lower NGL production margins reflecting lower equity volumes sold, partially offset by an improved energy commodity price environment in 2010 compared to 2009.

$6 million of lower equity earnings related to a $5 million decrease from Discovery Producer Services LLC (Discovery) primarily due to lower system gains and lower NGL revenues due to lower volumes.

The net decrease also reflects a $13 million increase in segment profit related to increased natural gas pipeline transportation revenues associated with expansion projects placed in service.

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Management s Discussion and Analysis (Continued)

Nine months ended September 30, 2010 vs. nine months ended September 30, 2009

The increase in *segment revenues* includes:

A $582 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are more than offset by similar changes in marketing purchases.

A $300 million increase in revenues associated with the production of NGLs reflecting an increase of $308 million associated with a 56 percent increase in average NGL per-unit sales prices.

A $13 million increase in transportation revenues associated with expansion projects placed into service in 2009.

A $10 million increase in fee revenues primarily due to new fees for processing natural gas production at Willow Creek, partially offset by reduced fees from lower deepwater gathering and transportation volumes.

A $9 million increase related to the sale of base gas from an abandoned storage field (offset in *segment cost and expenses*).

An $18 million decrease in natural gas pipeline transportation other service revenues due to reduced customer usage of our temporary natural gas loan and storage services and a $14 million decrease in revenues from lower natural gas pipeline transportation imbalance settlements in 2010 compared to 2009 (offset in *segment costs and expenses*).

The increase in s*egment costs and expenses* of $704 million includes:

A $604 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes more than offset similar changes in marketing revenues.

A $108 million increase in costs associated with the production of NGLs reflecting an increase of $105 million associated with a 44 percent increase in average natural gas prices.

An $18 million favorable change related to involuntary conversion gains due to insurance recoveries in excess of the carrying value of certain Gulf assets of $14 million and our Ignacio plant of $4 million.

The increase in William Partners *segment profit* includes:

$192 million of higher NGL production margins reflecting an improved energy commodity price environment in 2010 compared to 2009.

$23 million of higher equity earnings related to a $13 million increase from Discovery primarily due to recovery from the impact of the 2008 hurricanes, new volumes from the Tahiti pipeline lateral expansion completed in 2009, higher processing margins and an $8 million increase from Aux Sable primarily due to higher processing margins.

A $14 million favorable change in involuntary conversion gains.

A $10 million increase in fee revenues.

A $22 million decrease in NGL and crude marketing margins primarily due to unfavorable changes in pricing while product was in transit in 2010 as compared to favorable changes in pricing while product was in transit in 2009.

An $18 million decrease in natural gas pipeline transportation other service revenues.

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Management s Discussion and Analysis (Continued)

Exploration & Production

Exploration & Production includes the natural gas development, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States, development activities in the Eastern portion of the United States and oil and natural gas interests in South America. The gas management activities include procuring fuel and shrink gas for our midstream businesses and providing marketing services to third parties, such as producers. Additionally, gas management activities include the managing of various natural gas related contracts such as transportation, storage and related hedges not utilized for our own production.

Overview of Nine Months Ended September 30, 2010

Domestic production revenues for the first nine months of 2010 were higher than the first nine months of 2009 primarily due to higher net realized average prices on our natural gas production, partially offset by lower production volumes. Segment profit (loss) for the first nine months of 2010 includes approximately $1.7 billion in impairments of natural gas properties and goodwill (see further discussion below), while the first nine months of 2009 included expense of $32 million associated with contractual penalties from the early termination of drilling rig contracts. Highlights of the comparative periods, primarily related to our production activities, include:

	For the nine months ended September 30,		
	2010	2009	% Change
Average daily domestic production (MMcfe)(1)	1,116	1,184	-6%
Average daily total production (MMcfe)	1,171	1,237	-5%
Domestic production net realized average price ($/Mcfe)(2)	$ 4.57	$ 4.11	+11%
Capital expenditures ($ millions)	$ 1,477	$1,004	+47%
Domestic production revenues ($ millions)	$ 1,611	$1,518	+6%
Segment revenues ($ millions)	$ 3,090	$2,664	+16%
Segment profit (loss) ($ millions)	$(1,354)	$ 290	*

* Not meaningful due to change in signs.

(1) MMcfe is equal to one million cubic feet of gas equivalent.

(2) Mcfe is equal to one thousand cubic feet of gas equivalent. Net realized average prices include market prices, net of fuel and shrink and hedge gains and losses, less gathering and transportation

expenses. The realized hedge gain per Mcfe was $0.72 and $1.55 for the nine months ended September 30, 2010 and 2009, respectively.

During the second quarter of 2010, we entered into an agreement to acquire additional leasehold acreage positions and a 5 percent overriding royalty interest associated with these acreage positions. These acquisitions nearly double our acreage holdings in the Marcellus Shale and closed in July for $597 million, including closing adjustments. During 2010, we also spent a total of $102 million to acquire additional unproved leasehold acreage position in the Marcellus Shale.

As a result of significant declines in forward natural gas prices during third quarter 2010, we performed an interim assessment of our capitalized costs related to property and goodwill. As a result of these assessments, we recorded a $503 million impairment charge related to the capitalized costs of our Barnett Shale properties and a $175 million impairment charge related to capitalized costs of acquired unproved reserves in the Piceance Highlands, which were acquired in 2008. Additionally, we fully impaired our goodwill in the amount of $1 billion. These impairments were based on our assessment of estimated future discounted cash flows and other information. See Notes 4 and 10 of Notes to Consolidated Financial Statements for a further discussion of the impairments.

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Management s Discussion and Analysis (Continued)

Outlook for the Remainder of 2010

Our expectations and objectives for the remainder of the year include:

Continuation of our development drilling program in the Appalachian, Piceance, Fort Worth, Powder River, and San Juan basins. Our total remaining capital expenditures for 2010 are projected to be between $425 million and $625 million.

Annual average daily domestic production level consistent with 2009 volumes, with fourth quarter 2010 volumes likely to be higher than the prior year comparable period.

Risks to achieving our expectations and objectives include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions, domestic natural gas production levels and demand, and a slower recovery in the global economy than expected. A significant decline in natural gas prices would also impact these expectations for the remainder of the year, although the impact would be somewhat mitigated by our hedging program, which hedges a significant portion of our expected production. In addition, changes in laws and regulations may impact our development drilling program.

Commodity Price Risk Strategy

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative contracts for a portion of our future production. For the remainder of 2010, we have the following contracts for our daily domestic production, shown at weighted average volumes and basin-level weighted average prices:

		Remainder of 2010	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Collar agreements	Rockies	100	$6.53 $8.94
Collar agreements	San Juan	230	$5.75 $7.84
Collar agreements	Mid-Continent	105	$5.37 $7.41
Collar agreements	Southern California	45	$4.80 $6.43
Collar agreements	Other	30	$5.66 $6.89
NYMEX and basis fixed-price		120	$4.41

The following is a summary of our agreements and contracts for daily production for the three and nine months ended September 30, 2010 and 2009:

		2010		2009	
		Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars	Volume (MMcf/d)	Price ($/Mcf) Floor-Ceiling for Collars
Third Quarter:					
Collars	Rockies	100	$6.53 $8.94	150	$6.11 $9.04
Collars	San Juan	230	$5.75 $7.84	245	$6.58 $9.62
Collars	Mid-Continent	105	$5.37 $7.41	95	$7.08 $9.73
Collars	Southern California	45	$4.80 $6.43		
Collars	Other	30	$5.66 $6.89		
NYMEX and basis fixed-price		120	$4.35	106	$3.59
Year-to-Date:					
Collars	Rockies	100	$6.53 $8.94	150	$6.11 $9.04
Collars	San Juan	233	$5.74 $7.82	245	$6.58 $9.62
Collars	Mid-Continent	105	$5.37 $7.41	95	$7.08 $9.73
Collars	Southern California	45	$4.80 $6.43		

Collars Other	27	$5.63	$6.87		
NYMEX and basis fixed-price	120	$4.39		106	$3.59

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Management s Discussion and Analysis (Continued)

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We hold a long-term obligation to deliver on a firm basis 200,000 MMbtu per day of gas to a buyer at the White River Hub (Greasewood-Meeker, CO), which is the major market hub exiting the Piceance basin. Our interests in the Piceance basin hold sufficient reserves to meet this obligation.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
	(Millions)		**(Millions)**	
Segment revenues:				
Domestic production revenues	$ 530	$ 509	$ 1,611	$ 1,518
Gas management revenues	435	344	1,357	1,031
Net forward unrealized mark-to-market gains and ineffectiveness	16		25	9
Other revenues	31	26	97	106
Total segment revenues	$ 1,012	$ 879	$ 3,090	$ 2,664
Segment profit (loss)	$ (1,603)	$ 100	$ (1,354)	$ 290

Three months ended September 30, 2010 vs. three months ended September 30, 2009

The increase in total *segment revenues* is primarily due to the following:

The increase in domestic production revenues is primarily due to a 5 percent increase in realized average prices including the effect of hedges, offset by a slight decrease in production volumes sold. Production revenues in 2010 and 2009 include approximately $46 million and $22 million, respectively, related to natural gas liquids and approximately $14 million and $11 million, respectively, related to condensate.

The increase in gas management revenues is primarily due to a 40 percent increase in average prices on physical natural gas sales partially offset by a 10 percent decrease in natural gas sales volumes. This is primarily related to gas sales associated with our transportation and storage contracts and is offset by a similar increase in *segment costs and expenses.*

The increase in net forward unrealized mark-to-market gains and ineffectiveness is primarily due to price movements favorable to our derivative positions executed to hedge the anticipated withdrawal of natural gas from storage.

Total *segment costs and expenses* increased $1,837 million, primarily due to the following:

$1,681 million due to impairments to property and goodwill, as previously discussed.

$89 million increase in gas management expenses, primarily due to a 38 percent increase in average prices on physical natural gas purchases partially offset by a 10 percent decrease in natural gas purchase volumes. This increase is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is substantially offset by a similar increase in *segment revenues*. Gas management expenses in 2010 and 2009 also include $10 million and $5 million, respectively, related to costs for unutilized pipeline capacity.

$23 million higher exploration expenses due to $15 million in exploratory dry hole costs associated with our Paradox basin and $8 million in higher unproved lease amortization and seismic costs.

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Management s Discussion and Analysis (Continued)

$17 million higher operating taxes primarily due to higher average market prices (excluding the impact of hedges).

$12 million higher depletion, depreciation and amortization expenses primarily due to a higher capitalized cost per unit in 2010 as compared to 2009 as a result of the decrease in proved reserves in fourth quarter 2009 due to the new SEC reserves reporting rules and the related price impact.

$11 million higher lease, facility and other operating expenses generally due to workovers, additional maintenance and employee related costs.

$9 million higher gathering, processing, and transportation expenses primarily as a result of the processing of natural gas liquids at Williams Partners Willow Creek plant, which began processing in August 2009.

Partially offsetting the increased costs is $13 million of gains associated with sales of certain assets.

The $1,703 million decrease in *segment profit* is primarily due to the impairments and other increases in *segment costs and expenses,* partially offset by a 5 percent increase in realized average domestic prices.

Nine months ended September 30, 2010 vs. nine months ended September 30, 2009

The increase in total *segment revenues* is primarily due to the following:

The increase in domestic production revenues reflects an increase of $181 million associated with a 13 percent increase in realized average prices including the effect of hedges, partially offset by a decrease of $87 million associated with a 6 percent decrease in production volumes sold. Production revenues in 2010 and 2009 include approximately $139 million and $45 million, respectively, related to natural gas liquids and approximately $39 million and $25 million, respectively, related to condensate.

The increase in gas management revenues is primarily due to an increase in physical natural gas revenue as a result of a 33 percent increase in average prices on physical natural gas sales, partially offset by a slight decrease in natural gas sales volumes. This is primarily related to gas sales associated with our transportation and storage contracts and is offset by a similar increase in *segment costs and expenses.*

The increase in net forward unrealized mark-to-market gains and ineffectiveness is primarily due to price movements favorable to our derivative positions executed to hedge the anticipated withdrawal of natural gas from storage.

Partially offsetting the increased revenues is a $9 million decrease in other revenues, primarily due to the absence in 2010 of the 2009 recovery of certain royalty overpayments from prior years.

Total *segment costs and expenses* increased $2,073 million, primarily due to the following:

$1,681 million due to impairments to property and goodwill, as previously discussed.

$323 million increase in gas management expenses, primarily due to a 30 percent increase in average prices on physical natural gas purchases, partially offset by a slight decrease in natural gas purchase volumes. This increase is primarily related to the gas purchases associated with our previously discussed transportation and storage contracts and is substantially offset by a similar increase in *segment revenues*. Gas management expenses in 2010 and 2009 include $35 million and $14 million, respectively, related to charges for unutilized pipeline capacity. In addition, a $7 million unfavorable adjustment was made in 2009 to the carrying value of natural gas in storage reflecting a decline in the price of natural gas in 2009.

$53 million higher operating taxes primarily due to higher average market prices, excluding the impact of hedges.

$32 million higher gathering, processing, and transportation expenses primarily as a result of the processing

Management s Discussion and Analysis (Continued)

of natural gas liquids at Williams Partners Willow Creek plant, which began processing in August 2009.

$12 million higher depletion, depreciation and amortization expenses primarily due to a higher capitalized cost per unit in 2010 as compared to 2009 as a result of the decrease in proved reserves in fourth quarter 2009 due to the new SEC reserves reporting rules and the related price impact. The higher capitalized cost per unit was slightly offset by lower production volumes in 2010 as compared to 2009.

Partially offsetting the increased costs are decreases due to the absence of $32 million of expenses in 2009 related to penalties from the early release of drilling rigs as previously discussed. Also, 2010 includes $13 million of gains associated with sales of certain assets.

The $1,644 million decrease in s*egment profit* is primarily due to the impairments, partially offset by a 13 percent increase in realized average domestic prices on production and the other previously discussed changes in *segment revenues* and *segment costs and expenses.*

Other

Overview of Nine Months Ended September 30, 2010

Our Other segment primarily includes our Canadian midstream and domestic olefins operations and a 25.5 percent interest in Gulfstream Natural Gas System, L.L.C. (Gulfstream), as well as corporate operations. *Segment profit (loss)* for the nine months ended September 30, 2010 has improved compared to the prior year primarily due to $97 million higher NGL and olefins production margins resulting from significantly higher average per-unit margins on lower volumes and the net impact of recognizing $43 million in gains on the Accroven investment in 2010 while recording a $75 million impairment charge on that investment in 2009.

Significant events for 2010 include the following:

Sale of Accroven

In June 2010, we sold our 50 percent interest in Accroven to Petróleos de Venezuela S.A. (PDVSA) for $107 million. Of this amount, $13 million was received in cash at closing. Another $30 million was received in August 2010, and the remainder is due in six quarterly payments beginning October 31, 2010. Considering the deteriorating circumstances in Venezuela, we fully impaired our $75 million investment in Accroven in 2009. We are currently recognizing the resulting gain as cash is received.

Completion of the Butylene/Butane Splitter facility in Canada

The new butylene/butane splitter and hydro-treating facility was placed into service in August 2010. The butylene/butane splitter further fractionates the butylene/butane mix product produced at our Redwater fractionators near Edmonton, Alberta into separate butylene and butane products, which receive higher values and are in greater demand in the marketplace. The source of the product fractionated at Redwater is from our oil sands off-gas extraction facility near Fort McMurray, Alberta.

Outlook for the Remainder of 2010

The following factors could impact our business in 2010.

Commodity price changes

We anticipate average per-unit margins for 2010 will increase over 2009 levels. Margins in our Canadian midstream and domestic olefins business are highly dependent upon continued demand within the global economy. NGL products are currently the preferred feedstock for ethylene and propylene production which has been shifting away from the more expensive crude-based feedstocks. Bolstered by abundant long-term domestic natural gas supplies, we expect to benefit from these dynamics in the broader global petrochemical markets because of our NGL-based olefins production.

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Management s Discussion and Analysis (Continued)

Allocation of capital to projects

We expect to spend $150 million to $200 million in 2010 on capital projects. The major expansion projects include a 12-inch diameter pipeline in Canada, which will transport recovered natural gas liquids and olefins from our extraction plant in Fort McMurray to our Redwater fractionation facility. The pipeline will have sufficient capacity to transport additional recovered liquids in excess of those from our current agreements. Limited construction has begun and we anticipate an in-service date in 2012.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Segment revenues	$ 238	$ 222	$ 778	$ 550
Segment profit (loss)	$ 80	$ 31	$ 186	$ (13)

Three months ended September 30, 2010 vs. three months ended September 30, 2009

Segment revenues increased primarily due to $43 million in higher NGL and olefins production revenues associated with higher average per-unit prices. The new butylene/butane splitter began producing and selling both butylene and butane in August 2010.

Partially offsetting the increased revenues are decreases due to:

$18 million lower marketing revenues which resulted from significantly lower volumes, partially offset by general increases in energy commodity prices. The lower marketing revenues were offset by similar changes in marketing purchases described below.

$9 million decrease primarily due to 6 percent lower Gulf ethylene sales volumes, 20 percent lower Canadian propylene sales volumes resulting from 2010 plant compressor maintenance and 22 percent lower Canadian propane sales volumes.

Segment costs and expenses decreased $4 million primarily due to:

$18 million decreased marketing purchases resulting from significantly lower volumes on higher per-unit purchases. The decreased marketing purchases offset similar changes in marketing revenues.

$7 million in reduced costs associated with the lower sales volumes described above.

Partially offsetting the decreased costs are increases due to:

$16 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs.

$5 million higher operating costs and general and administrative costs in our Canadian midstream and domestic olefins operations.

The favorable change in *segment profit (loss)* is primarily due to a $30 million gain recognized in third-quarter 2010 and $25 million higher NGL and olefins production margins resulting from higher per-unit margins on lower ethylene, propylene and propane volumes.

Nine months ended September 30, 2010 vs. nine months ended September 30, 2009

Segment revenues increased primarily due to:

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Management s Discussion and Analysis (Continued)

$266 million higher NGL and olefins production revenues resulting from significantly higher average per-unit prices. The new butylene/butane splitter began producing and selling both butylene and butane in August 2010.

$14 million higher marketing revenues due to general increases in energy commodity prices on lower volumes. The higher marketing revenues were more than offset by similar changes in marketing purchases described below.

Partially offsetting the increased revenues was a $51 million decrease from lower sales volumes primarily due to:

22 percent lower propylene volumes available for processing at our Gulf propylene splitter.

6 percent lower Gulf ethylene sales volumes.

21 percent lower Canadian NGL volumes resulting from operational issues at a third-party facility which provides our feedstock and from plant compressor maintenance.

22 percent lower Canadian propylene volumes resulting from operational issues at a third-party facility which provides our feedstock and from plant compressor maintenance.

Segment costs and expenses increased $142 million primarily as a result of:

$159 million higher NGL and olefins production product costs resulting from higher average per-unit feedstock costs.

$17 million increased marketing purchases due to general increases in energy commodity prices on lower volumes. The increased marketing purchases more than offset similar changes in marketing revenues.

$6 million higher operating costs in our Canadian midstream and domestic olefins operations.

Partially offsetting the increased costs are decreases due to:

$41 million of reduced product costs resulting from the lower sales volumes described above.

$6 million favorable customer settlement received in 2010.

The favorable change in *segment profit (loss)* is primarily due to $97 million higher NGL and olefins production margins resulting from significantly higher average per-unit margins on lower volumes and the net impact of recognizing $43 million in gains on the Accroven investment in 2010 while recording a $75 million impairment charge on that investment in 2009.

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Strategic Restructuring

On February 17, 2010, we completed a strategic restructuring, which involved contributing a substantial majority of our domestic midstream and gas pipeline businesses into WPZ. We intend to hold our WPZ limited partner and general partner units for the long-term. As consideration for the asset contributions, we received proceeds from WPZ s debt issuance of approximately $3.5 billion, less WPZ s transaction fees and expenses and other post-closing adjustments, as well as 203 million WPZ Class C units, which received a prorated initial distribution and were then converted to regular common units on May 10, 2010. We also maintained our 2 percent general partner interest. WPZ assumed approximately $2 billion of existing debt associated with the gas pipeline assets. In connection with the restructuring, we retired $3 billion of our debt and paid $574 million in related premiums. These amounts, as well as other transaction costs, were primarily funded with the cash consideration we received from WPZ. As a result of our restructuring, we are better positioned to drive additional growth and pursue value-adding growth strategies. Our new structure is designed to lower capital costs, enhance reliable access to capital markets, and create a greater ability to pursue development projects and acquisitions.

Outlook

For 2010, we expect operating cash flows to be generally consistent with 2009 levels. Lower-than-expected energy commodity prices would be somewhat mitigated by certain of our cash flow streams that are substantially insulated from changes in commodity prices as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts from our gas pipelines;
- Hedged natural gas sales at Exploration & Production related to a significant portion of its production;
- Fee-based revenues from certain gathering and processing services in our midstream businesses.

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, and debt payments while maintaining a sufficient level of liquidity. In particular, we note the following assumptions for the year:

- We expect to maintain consolidated liquidity of at least $1 billion from *cash and cash equivalents* and unused revolving credit facilities.
- We expect to fund capital and investment expenditures, debt payments, dividends, and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, utilization of our revolving credit facilities, and proceeds from debt issuances and sales of equity securities as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $2.4 billion and $2.7 billion in 2010.
- We expect capital and investment expenditures to total between $3.425 billion and $3.825 billion in 2010. Of this total, a significant portion of Williams Partners expected expenditures of $1.375 billion to $1.545 billion (excluding the announced acquisition of Piceance basin gathering and processing assets from Exploration & Production) are considered nondiscretionary to meet legal, regulatory, and/or contractual requirements or to fund committed growth projects. Exploration & Production s expected expenditures of $1.9 billion to $2.1 billion are considered primarily discretionary. See Results of Operations Segments, Williams Partners and Exploration & Production for discussions describing the general nature of these expenditures.

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

- Lower than expected levels of cash flow from operations;
- Sustained reductions in energy commodity prices from the range of current expectations.

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Management s Discussion and Analysis (Continued)

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2010. Our internal and external sources of consolidated liquidity include cash generated from our operations, cash and cash equivalents on hand, and our credit facilities. Additional sources of liquidity, if needed, include bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. These sources are available to us at the parent level and are expected to be available to certain of our subsidiaries, particularly equity and debt issuances from WPZ. WPZ is expected to be self-funding through its cash flows from operations, use of its credit facility, and its access to capital markets. Cash held by WPZ is available to us through distributions in accordance with the partnership agreement. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

		September 30, 2010		
Available Liquidity	**Expiration**	**WPZ**	**WMB**	**Total**
			(Millions)	
Cash and cash equivalents		$ 92	$ 923 (1)	$ 1,015
Available capacity under our unsecured revolving and letter of credit facilities:				
$700 million facilities (2)	October 1, 2010			
$900 million facility (3)	May 1, 2012		827	827
Capacity available to Williams Partners L.P. under its $1.75 billion senior unsecured credit facility (3)	February 17, 2013	1,750		1,750
		$ 1,842	$ 1,750	$ 3,592

(1) *Cash and cash equivalents* includes $32 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 $490 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) These facilities were originated primarily in support of our former power business. At September 30, 2010, we are in compliance with the financial covenants associated with these credit facilities.

(3) At September 30, 2010, we are in compliance with the financial covenants associated with these credit facilities. See Note 9 of Notes to Consolidated Financial Statements.

In addition to the credit facilities listed above, we have issued letters of credit totaling $50 million as of September 30, 2010 under certain bilateral agreements.

WPZ filed a shelf registration statement as a well-known, seasoned issuer in October 2009 that allows it to issue an unlimited amount of registered debt and limited partnership unit securities.

At the parent-company level, we filed a shelf registration statement as a well-known, seasoned issuer in May 2009 that allows us to issue an unlimited amount of registered debt and equity securities.

Exploration & Production has an unsecured credit agreement with certain banks that, so long as certain conditions are met, 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 July 2010, the agreement term was extended from December 2013 to December 2015. The impairments of goodwill, natural gas producing properties and acquired unproved reserves recorded by our Exploration & Production segment in the third quarter of 2010 (see Notes 4 and 10 of Notes to Consolidated Financial Statements) will not impact our ability to utilize Exploration & Production s credit agreement to facilitate hedging our future natural gas production.

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Management s Discussion and Analysis (Continued)

Credit Ratings

Our ability to borrow money is impacted by our credit ratings and the credit ratings of WPZ. The current ratings are as follows:

	WMB	WPZ
Standard and Poor s (1)		
Corporate Credit Rating	BBB-	BBB-
Senior Unsecured Debt Rating	BB+	BBB-
Outlook	Positive	Positive
Moody s Investors Service (2)		
Senior Unsecured Debt Rating	Baa3	Baa3
Outlook	Stable	Stable
Fitch Ratings (3)		
Senior Unsecured Debt Rating	BBB-	BBB-
Outlook	Stable	Stable

(1) 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.

(2) 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 that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates the lower end of the category.

(3) 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.

Credit rating agencies perform independent analyses when assigning credit ratings. No assurance can be given that the credit rating agencies will continue to assign us investment grade ratings even if we meet or exceed their current criteria for investment grade ratios. A downgrade of our credit rating might increase our future cost of borrowing and would require us to post additional collateral with third parties, negatively impacting our available liquidity. As of September 30, 2010, we estimate that a downgrade to a rating below investment grade for WMB or WPZ would require us to post up to $516 million or $60 million, respectively, in additional collateral with third parties.

Sources (Uses) of Cash

	Nine months ended September 30,	
	2010	**2009**
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,941	$ 1,758
Financing activities	(321)	261
Investing activities	(2,472)	(1,818)
Increase (decrease) in cash and cash equivalents	$ (852)	$ 201

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Management s Discussion and Analysis (Continued)

Operating activities

Our *net cash provided by operating activities* for the nine months ended September 30, 2010, increased from the same period in 2009 primarily due to the improvement in the energy commodity price environment in the first nine months of 2010 as compared to the first nine months of 2009.

Financing activities

Significant transactions include:

$430 million received in revolver borrowings from WPZ s $1.75 billion unsecured credit facility primarily used to fund our increased ownership in OPPL, a transaction that closed in September 2010;

$380 million received from WPZ s September 2010 equity offering used to reduce WPZ s revolver borrowings mentioned above;

$3.491 billion received by WPZ in February 2010 from the issuance of $3.5 billion of senior unsecured notes related to our previously discussed restructuring (see Note 9 of Notes to Consolidated Financial Statements);

$3 billion of senior unsecured notes retired in February 2010 and $574 million paid in associated premiums utilizing proceeds from the $3.5 billion debt issuance (see Note 9 of Notes to Consolidated Financial Statements);

$250 million received from revolver borrowings on WPZ s $1.75 billion unsecured credit facility in February 2010 to repay a term loan. As of September 30, 2010, no loans are outstanding on this credit facility (see Note 9 of Notes to Consolidated Financial Statements);

$595 million net cash received in 2009 from the issuance of $600 million aggregate principal amount of 8.75 percent senior unsecured notes due 2020 to fund general corporate expenses and capital expenditures.

Investing activities

Significant transactions include:

$424 million cash payment for WPZ s September 2010 acquisition of an increased interest in OPPL (see Results of Operations Segments, Williams Partners);

Capital expenditures totaled $2,111 million and $1,829 million for 2010 and 2009, respectively. Included is approximately $597 million, including closing adjustments, related to Exploration & Production s acquisition in the Marcellus Shale in July 2010 (see Results of Operations Segments, Exploration & Production);

$148 million of cash received in 2009 as a distribution from Gulfstream following its debt offering;

$100 million cash payment in 2009 for our 51 percent ownership in the joint venture Laurel Mountain.

Off-Balance Sheet Financing Arrangements and Guarantees of Debt or Other Commitments

We have various other guarantees and commitments which are disclosed in Notes 11 and 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.

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Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first nine months of 2010. (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 (NGL), as well as other market factors, such as market volatility and energy 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 many factors, including 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 portfolios 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. Contracts designated as normal purchases or sales 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. The fair value of our trading derivatives was a net liability of $1 million at September 30, 2010. The value at risk for contracts held for trading purposes was less than $1 million at September 30, 2010 and December 31, 2009.

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
Williams Partners	Natural gas purchases NGL sales
Exploration & Production	Natural gas purchases and sales
Other	NGL purchases

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The fair value of our nontrading derivatives was a net asset of $415 million at September 30, 2010.

The value at risk for derivative contracts held for nontrading purposes was $24 million at September 30, 2010, and $34 million at December 31, 2009.

Certain of the derivative contracts held for nontrading purposes are accounted for as cash flow hedges. Of the total fair value of nontrading derivatives, cash flow hedges had a net asset value of $417 million as of September 30, 2010. 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.

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Item 4
Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (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 Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our 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.

Third-Quarter 2010 Changes in Internal Controls

In the third quarter, our Williams Partners business segment completed the first phase of implementing a new measurement system for use in its midstream business. The implementation will be completed in the fourth quarter.

Other than described above, there have been no changes during the third quarter of 2010 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

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, 2009, 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:

Costs of environmental liabilities and complying with existing and future environmental regulations, including those related to climate change and greenhouse gas emissions, could exceed our current expectations.

Our operations are subject to extensive environmental regulation pursuant to a variety of federal, provincial, state and municipal laws and regulations. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, extraction, transportation, treatment and disposal of hazardous substances and wastes, in connection with spills, releases and emissions of various substances into the environment, and in connection with the operation, maintenance, abandonment and reclamation of our facilities. Various governmental authorities, including the U.S. Environmental Protection Agency (EPA) and analogous state agencies and the United States Department of Homeland Security, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations, and permits may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, and the issuance of injunctions limiting or preventing some or all of our operations.

Compliance with environmental laws requires significant expenditures, including clean up costs and damages arising out of contaminated properties. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations for the remediation of contaminated areas and in connection with spills or releases of natural gas and wastes on, under, or from our properties and facilities. Private parties, including the owners of properties through which our pipeline and gathering systems pass, may have the right to pursue legal actions to enforce compliance as well as to seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage arising from our operations.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses. Although we do not expect that the costs of complying with current environmental laws will have a material adverse effect on our financial condition or results of operations, no assurance can be given that the costs of complying with environmental laws in the future will not have such an effect.

Legislative and regulatory responses related to greenhouse gases (GHGs) and climate change creates the potential for financial risk. The United States Congress and certain states have for some time been considering various forms of legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. In addition, increased public awareness and concern may result in more state, federal, and international proposals to reduce or mitigate GHG emissions.

Several bills have been introduced in the United States Congress that would compel GHG emission reductions. In June of 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act which is intended to decrease annual GHG emissions through a variety of measures, including a cap and trade system which limits the amount of GHGs that may be emitted and incentives to reduce the nation s dependence on traditional energy sources. The U.S. Senate is currently considering similar legislation, and numerous states have also announced or adopted programs to stabilize and reduce GHGs. In addition, on December 7, 2009, the EPA issued a final determination that six GHGs are a threat to public safety and welfare. This determination is the latest in a series of EPA actions in 2009 which could ultimately lead to the direct regulation of GHG emissions in our industry by the EPA under the Clean Air Act. While it is not clear whether or when any federal or state climate change laws or regulations will be passed, any of these actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities, and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively impact our cost of and access to capital.

Certain environmental and other groups have suggested that additional laws and regulations may be needed to more closely regulate the hydraulic fracturing process commonly used in natural gas production and legislation has been proposed in Congress to provide for such regulation. We cannot predict whether any federal, state or local legislation or regulation will be enacted in this area and if so, what its provisions would be. If additional levels of reporting, regulation and permitting were required, our operations and those of our customers could be adversely affected.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change. Our regulatory rate structure and our contracts with customers might not necessarily allow us to recover capital costs we incur to comply with the new environmental regulations. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for certain development projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, the operation of our facilities could be prevented or become subject to additional costs, resulting in potentially material adverse consequences to our results of operations.

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The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

In July 2010, federal legislation known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted. The Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Among other things, the Act provides for the creation of position limits for certain derivatives transactions, as well as requiring certain transactions to be cleared on exchanges for which cash collateral will be required. The final impact of the Act on our hedging activities is uncertain at this time due to the requirement that the SEC and the Commodities Futures Trading Commission (CFTC) promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. These new rules and regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts or reduce the availability of derivatives. Although we believe the derivative contracts that we enter into should not be impacted by position limits and should be exempt from the requirement to clear transactions through a central exchange or to post collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could impact liquidity and reduce our cash available for capital expenditures. A requirement to post cash collateral could therefore reduce our ability to execute hedges to reduce commodity price uncertainty and thus protect cash flows. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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Item 6. Exhibits

Exhibit 3.1	Restated Certificate of Incorporation (filed on May 26, 2010, as Exhibit 3.1 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 3.2	Restated By-Laws (filed on May 26, 2010, as Exhibit 3.2 to the Company s Current Report on Form 8-K) and incorporated herein by reference.
Exhibit 10.1	Amendment Agreement, dated May 9, 2007, among The Williams Companies, Inc., Williams Partners L.P., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, certain banks, financial institutions and other institutional lenders and Citibank, N.A., as Administrative Agent. (1)
Exhibit 10.2	Credit Agreement dated as of May 1, 2006, among The Williams Companies, Inc., Northwest Pipeline Corporation, Transcontinental Gas Pipe Line Corporation, and Williams Partners L.P., as Borrowers and Citibank, N.A., as Administrative Agent. (1)
Exhibit 10.3	Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners. (1)
Exhibit 10.4	First Amendment dated March 30, 2007 to Credit Agreement dated February 23, 2007 among Williams Production RMT Company, Williams Production Company, LLC, Citibank, N.A., Citigroup Energy Inc., Calyon New York Branch, and the banks named therein, and Citigroup Global Markets Inc. and Calyon New York Branch as joint lead arrangers and co-book runners. (1)
Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.(1)
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.(1)
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.(1)
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.(2)
Exhibit 101.INS	XBRL Instance Document.(2)
Exhibit 101.SCH	XBRL Taxonomy Extension Schema.(2)
Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase.(2)
Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase.(2)

Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase.(2)
Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase.(2)

(1) Filed herewith.

(2) Furnished herewith.

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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)

October 28, 2010

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