WILLIAMS COMPANIES INC
Form 10-Q
August 04, 2011

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

(Mark One)

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

For the quarterly period ended June 30, 2011

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, including area code: (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 August 1, 2011
Common Stock, $1 par value	588,895,011 Shares

The Williams Companies, Inc.
Index

	Page
Part I. Financial Information	
Item 1. Financial Statements	
Consolidated Statement of Operations Three and Six Months Ended June 30, 2011 and 2010	3
Consolidated Balance Sheet June 30, 2011 and December 31, 2010	4
Consolidated Statement of Changes in Equity Three and Six Months Ended June 30, 2011 and 2010	5
Consolidated Statement of Cash Flows Six Months Ended June 30, 2011 and 2010	6
Notes to Consolidated Financial Statements	7
Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations	30
Item 3. Quantitative and Qualitative Disclosures About Market Risk	57
Item 4. Controls and Procedures	59
Part II. Other Information	59
Item 1. Legal Proceedings	59
Item 1A. Risk Factors	59
Item 6. Exhibits	61

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;

- Natural gas, natural gas liquids, and crude oil 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 and oil 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 climate change regulation 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 (SEC).

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, 2010, 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 June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Revenues:				
Williams Partners	$ 1,671	$ 1,400	$ 3,250	$ 2,890
Exploration & Production	981	901	1,970	2,058
Midstream Canada & Olefins	347	257	663	529
Other	7	5	13	11
Intercompany eliminations	(337)	(274)	(652)	(608)
Total revenues	2,669	2,289	5,244	4,880
Segment costs and expenses:				
Costs and operating expenses	1,938	1,717	3,846	3,634
Selling, general, and administrative expenses	134	123	271	234
Other (income) expense net	3	(12)	2	(13)
Total segment costs and expenses	2,075	1,828	4,119	3,855
General corporate expenses	47	45	98	130
Operating income (loss):				
Williams Partners	435	334	847	732
Exploration & Production	89	68	134	216
Midstream Canada & Olefins	72	61	146	81
Other	(2)	(2)	(2)	(4)
General corporate expenses	(47)	(45)	(98)	(130)
Total operating income (loss)	547	416	1,027	895
Interest accrued	(156)	(154)	(314)	(318)
Interest capitalized	9	13	18	30
Investing income net	45	55	96	94
Early debt retirement costs				(606)
Other income (expense) net		(1)	4	(8)
Income (loss) from continuing operations before income taxes	445	329	831	87
Provision (benefit) for income taxes	145	104	139	10
Income (loss) from continuing operations	300	225	692	77
Income (loss) from discontinued operations	(3)	(3)	(11)	(1)
Net income (loss)	297	222	681	76
Less: Net income attributable to noncontrolling interests	70	37	133	84

Net income (loss) attributable to The Williams Companies, Inc.	$ 227	$ 185	$ 548	$ (8)
Amounts attributable to The Williams Companies, Inc.:				
Income (loss) from continuing operations	$ 230	$ 188	$ 559	$ (7)
Income (loss) from discontinued operations	(3)	(3)	(11)	(1)
Net income (loss)	$ 227	$ 185	$ 548	$ (8)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ .39	$ .32	$ .95	$ (.01)
Income (loss) from discontinued operations			(.02)	
Net income (loss)	$ .39	$ .32	$ .93	$ (.01)
Weighted-average shares (thousands)	588,310	584,414	587,641	584,173
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ .38	$ .31	$ .94	$ (.01)
Income (loss) from discontinued operations			(.02)	
Net income (loss)	$ .38	$ .31	$ .92	$ (.01)
Weighted-average shares (thousands)	597,633	592,498	597,097	584,173
Cash dividends declared per common share	$ .200	$ .125	$ .325	$ .235

See accompanying notes.

3

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

(Dollars in millions, except per-share amounts)	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,166	$ 795
Accounts and notes receivable (net of allowance of $17 at June 30, 2011 and $15 at December 31, 2010)	913	859
Inventories	282	302
Derivative assets	263	400
Other current assets and deferred charges	206	174
Total current assets	2,830	2,530
Investments	1,463	1,344
Property, plant, and equipment, at cost	31,442	30,365
Accumulated depreciation, depletion, and amortization	(10,842)	(10,144)
Property, plant, and equipment net	20,600	20,221
Derivative assets	138	173
Other assets and deferred charges	674	704
Total assets	$ 25,705	$ 24,972
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 988	$ 918
Accrued liabilities	915	1,002
Derivative liabilities	104	146
Long-term debt due within one year	383	508
Total current liabilities	2,390	2,574
Long-term debt	8,927	8,600
Deferred income taxes	3,572	3,448
Derivative liabilities	112	143
Other liabilities and deferred income	1,659	1,588
Contingent liabilities and commitments (Note 12)		
Equity:		
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 623 million shares issued at June 30, 2011 and 620 million shares issued at December 31, 2010)	623	620

Capital in excess of par value	8,351	8,269
Retained earnings (deficit)	(122)	(478)
Accumulated other comprehensive income (loss)	(95)	(82)
Treasury stock, at cost (35 million shares of common stock)	(1,041)	(1,041)
Total stockholders equity	7,716	7,288
Noncontrolling interests in consolidated subsidiaries	1,329	1,331
Total equity	9,045	8,619
Total liabilities and equity	$ 25,705	$ 24,972

See accompanying notes.

4

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

	Three months ended June 30,					
	2011			2010		
(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,537	$ 1,342	$ 8,879	$ 7,919	$ 1,043	$ 8,962
Comprehensive income (loss):						
Net income (loss)	227	70	297	185	37	222
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	8		8	(42)	1	(41)
Foreign currency translation adjustments	5		5	(29)		(29)
Pension and other postretirement benefits net	5		5	5		5
Unrealized gain (loss) on equity securities	3		3			
Total other comprehensive income (loss)	21		21	(66)	1	(65)
Total comprehensive income (loss)	248	70	318	119	38	157
Cash dividends common stock	(118)		(118)	(73)		(73)
Dividends and distributions to noncontrolling interests		(53)	(53)		(34)	(34)
Stock-based compensation, net of tax	17		17	13		13
Issuance of common stock from 5.5% debentures conversion	2		2			
Changes in Williams Partners L.P. ownership interest (Note 2)	30	(30)				
Other				1		1
Ending balance	$ 7,716	$ 1,329	$ 9,045	$ 7,979	$ 1,047	$ 9,026

	Six months ended June 30,					
	2011			2010		

(Millions)	The Williams Companies, Inc.	Noncontrolling Interests	Total	The Williams Companies, Inc.	Noncontrolling Interests	Total
Beginning balance	$ 7,288	$ 1,331	$ 8,619	$ 8,447	$ 572	$ 9,019
Comprehensive income (loss):						
Net income (loss)	548	133	681	(8)	84	76
Other comprehensive income (loss), net of tax:						
Net change in cash flow hedges	(54)		(54)	105	3	108
Foreign currency translation adjustments	27		27	(10)		(10)
Pension and other postretirement benefits net	11		11	10		10
Unrealized gain (loss) on equity securities	3		3			
Total other comprehensive income (loss)	(13)		(13)	105	3	108
Total comprehensive income (loss)	535	133	668	97	87	184
Cash dividends common stock	(191)		(191)	(137)		(137)
Dividends and distributions to noncontrolling interests		(105)	(105)		(66)	(66)
Stock-based compensation, net of tax	52		52	25		25
Issuance of common stock from 5.5% debentures conversion	2		2			
Changes in Williams Partners L.P. ownership interest (Note 2)	30	(30)		(454)	454	
Other				1		1
Ending balance	$ 7,716	$ 1,329	$ 9,045	$ 7,979	$ 1,047	$ 9,026

See accompanying notes.

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

(Millions)	Six months ended June 30, 2011	2010
OPERATING ACTIVITIES:		
Net income (loss)	$ 681	$ 76
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation, depletion, and amortization	784	727
Provision (benefit) for deferred income taxes	87	50
Provision for loss on investments, property and other assets	51	10
Amortization of stock-based awards	25	26
Early debt retirement costs		606
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(56)	115
Inventories	20	(57)
Margin deposits and customer margin deposits payable	(30)	5
Other current assets and deferred charges	(9)	(6)
Accounts payable	109	(89)
Accrued liabilities	30	(157)
Changes in current and noncurrent derivative assets and liabilities	14	(34)
Other, including changes in noncurrent assets and liabilities	(22)	25
Net cash provided by operating activities	1,684	1,297
FINANCING ACTIVITIES:		
Proceeds from long-term debt	425	3,749
Payments of long-term debt	(225)	(3,515)
Dividends paid	(191)	(137)
Dividends and distributions paid to noncontrolling interests	(105)	(66)
Payments for debt issuance costs	(19)	(66)
Premiums paid on early debt retirements		(574)
Other net	1	(21)
Net cash used by financing activities	(114)	(630)
INVESTING ACTIVITIES:		
Capital expenditures*	(1,094)	(940)
Purchases of investments/advances to affiliates	(132)	(20)
Other net	27	27
Net cash used by investing activities	(1,199)	(933)
Increase (decrease) in cash and cash equivalents	371	(266)
Cash and cash equivalents at beginning of period	795	1,867

Cash and cash equivalents at end of period	$ 1,166	$ 1,601
* Increases to property, plant, and equipment	$ (1,086)	$ (898)
Changes in related accounts payable and accrued liabilities	(8)	(42)
Capital expenditures	$ (1,094)	$ (940)

See accompanying notes.

6

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 June 1, 2011. The accompanying unaudited financial statements include all normal recurring adjustments and others that, in the opinion of management, are necessary to present fairly our financial position at June 30, 2011, results of operations and changes in equity for the three and six months ended June 30, 2011 and 2010, and cash flows for the six months ended June 30, 2011 and 2010.

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 16, 2011, we announced that our Board of Directors approved our reorganization plan to divide our business into two separate, publicly traded corporations. On April 29, 2011, our wholly owned subsidiary, WPX Energy, Inc. (WPX), filed a registration statement with the Securities and Exchange Commission (SEC) with respect to an initial public offering (IPO) of its equity securities and on July 28, 2011, WPX filed the third amendment to its registration statement with the SEC. This is the first step in our reorganization plan, which calls for a separation of our exploration and production business through an IPO and a subsequent tax-free spin-off of our remaining interest in WPX to our shareholders. We retain the discretion to determine whether and when to complete these transactions.

Note 2. Basis of Presentation

Our operations are located principally in the United States and are organized into the following reporting segments: Williams Partners, Exploration & Production and Midstream Canada & Olefins. All remaining business activities are included in Other.

Williams Partners consists of our consolidated master limited partnership, Williams Partners L.P. (WPZ) and includes our gas pipeline and domestic midstream businesses. The gas pipeline businesses include 100 percent of Transcontinental Gas Pipe Line Company, LLC (Transco), 100 percent of Northwest Pipeline GP (Northwest Pipeline), and 49 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). WPZ s midstream operations are composed of significant, large-scale operations in the Rocky Mountain and Gulf Coast regions, operations in Pennsylvania s Marcellus Shale region, and various equity investments in domestic processing, fractionation, and natural gas liquid (NGL) transportation assets. WPZ s midstream assets also include substantial operations and investments in the Four Corners region, as well as an NGL fractionator and storage facilities near Conway, Kansas.

Exploration & Production includes the natural gas development, production and gas management activities, with operations primarily in the Rocky Mountain and Mid-Continent regions of the United States, natural gas development activities in the northeastern portion of the United States, oil and natural gas interests in South America, and oil development activities in the northern United States. 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 managing various natural gas related contracts such as transportation, storage, and related hedges.

Our Midstream Canada & Olefins segment includes our oil sands off-gas processing plant near Fort McMurray, Alberta, our NGL/olefin fractionation facility and butylene/butane splitter facility at Redwater, Alberta, our NGL light-feed olefins cracker in Geismar, Louisiana, along with associated ethane and propane pipelines, and our refinery grade splitter in Louisiana.

Other includes other business activities that are not operating segments and corporate operations.

Notes (Continued)

During second-quarter 2011, we contributed a 24.5 percent interest in Gulfstream to WPZ in exchange for aggregate consideration of $297 million of cash, 632,584 limited partner units, and an increase in the capital account of its general partner to allow us to maintain our 2 percent general partner interest. Williams Partners now holds a 49 percent interest in Gulfstream. We also own an additional one percent interest in Gulfstream, reported within Other. Prior period segment disclosures have not been adjusted for this transaction as the impact, which was less than 2.5 percent of Williams Partners segment profit for all periods affected, was not material. Equity earnings related to this interest in Gulfstream that have not been recast are $4 million and $7 million for the three months and $12 million and $15 million for the six months ended June 30, 2011 and 2010, respectively. Equity earnings related to this interest in Gulfstream for the years ended December 31, 2010, 2009 and 2008 are $32 million, $30 million, and $27 million, respectively.

During fourth-quarter 2010, we contributed a business represented by certain gathering and processing assets in Colorado s Piceance basin to WPZ. The operations of this business and the related assets and liabilities were previously reported through our Exploration & Production segment, however they are now reported in our Williams Partners segment. Prior period segment disclosures have been recast for this transaction.

Master Limited Partnership

At June 30, 2011, we own approximately 75 percent of the interests in WPZ, including the interests of the general partner, which is wholly owned by us, and incentive distribution rights.

WPZ is self funding and maintains separate lines of bank credit and cash management accounts. Cash distributions from WPZ to us, including any associated with our incentive distribution rights, occur through the normal partnership distributions from WPZ to all partners.

The change in WPZ ownership between us and the noncontrolling interests as a result of our February 2010 strategic restructuring was accounted for as an equity transaction and resulted 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 originally 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 amounts for the six months ended June 30, 2010 have been adjusted for the correction in the Consolidated Statement of Changes in Equity.

Discontinued Operations

The accompanying consolidated financial statements and notes reflect the results of operations and financial position of Exploration & Production s Arkoma basin operations as discontinued operations for all periods. (See Note 3.)

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

Accounting Standards Issued But Not Yet Adopted

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2011-4, Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS (ASU 2011-4). ASU 2011-4 primarily eliminates the differences in fair value measurement principles between the FASB and International Accounting Standards Board. It clarifies existing guidance, changes certain fair value measurements and requires expanded disclosure primarily related to Level 3 measurements and transfers between Level 1 and Level 2 of the fair value hierarchy. ASU 2011-4 is effective on a prospective basis for interim and annual periods beginning after December 15, 2011. We are assessing the application of this Update to our Consolidated Financial Statements.

In June 2011, the FASB issued Accounting Standards Update No. 2011-5, Comprehensive Income (Topic 220)

Notes (Continued)
Presentation of Comprehensive Income (ASU 2011-5). ASU 2011-5 requires presentation of net income and other comprehensive income either in a single continuous statement or in two separate, but consecutive, statements. The Update requires separate presentation in both net income and other comprehensive income of reclassification adjustments for items that are reclassified from other comprehensive income to net income. The new guidance does not change the items reported in other comprehensive income, nor affect how earnings per share is calculated and presented. We currently report net income in the Consolidated Statement of Operations and report other comprehensive income in the Consolidated Statement of Changes in Equity. The standard is effective beginning the first quarter of 2012, with a retrospective application to prior periods. We plan to apply the new presentation beginning in 2012.

Note 3. Discontinued Operations

Summarized Results of Discontinued Operations

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Revenues	$ 4	$ 4	$ 7	$ 9
Income (loss) from discontinued operations before impairments and income taxes	$	$ (2)	$ (2)	$ 2
Impairments	(2)		(11)	
(Provision) benefit for income taxes	(1)	(1)	2	(3)
Income (loss) from discontinued operations	$ (3)	$ (3)	$ (11)	$ (1)

Impairments in 2011 reflect write-downs to an estimate of fair value less costs to sell the assets of our Arkoma basin operations. This nonrecurring fair value measurement, which falls within Level 3 of the fair value hierarchy, was based on a probability-weighted discounted cash flow analysis that included purchase offers we have received for the assets.

The assets of our discontinued operations comprise significantly less than 0.5 percent of our total consolidated assets as of June 30, 2011, and December 31, 2010, and are reported primarily within *other current assets and deferred charges* and *other assets and deferred charges*, respectively, on our Consolidated Balance Sheet. Liabilities of our discontinued operations are insignificant for these periods.

Note 4. Asset Sales and Other Accruals

Other (income) expense net within *segment costs and expenses* in 2011 includes $10 million related to the reversal of project feasibility costs from expense to capital at Williams Partners, associated with a natural gas pipeline expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates.

Additional Items

We completed a strategic restructuring transaction in the first quarter of 2010 that involved significant debt issuances, retirements and amendments. During the six months ended June 30, 2010, we incurred significant costs related to these transactions, as follows:

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

$41 million of other transaction costs reflected in *general corporate expenses,* of which $5 million is attributable to noncontrolling interests;

Notes (Continued)

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

Exploration & Production recorded a $14 million unfavorable adjustment to *costs and operating expenses* for the six months ended June 30, 2011, related to the correction of an error associated with our estimate of accrued minimum annual charges for compression service contracts in the Powder River basin.

We recognized an $11 million gain in the first quarter of 2011 on the 2010 sale of our interest in Accroven SRL, reflecting the receipt of the first of six quarterly payments, which was originally due from the buyer in October 2010. We also recognized a $13 million gain in the second quarter of 2010 related to cash received at the closing of this sale. These gains are reflected within *investing income net* at Other. Payments are recognized as income upon receipt until such point future collections are reasonably assured.

Note 5. Provision (Benefit) for Income Taxes

The *provision (benefit) for income taxes* includes:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Current:				
Federal	$ 30	$ 70	$ 47	$ (43)
State	2	5	3	(9)
Foreign	16	8	(2)	13
	48	83	48	(39)
Deferred:				
Federal	86	15	78	38
State	7	3	8	6
Foreign	4	3	5	5
	97	21	91	49
Total provision (benefit)	$ 145	$ 104	$ 139	$ 10

The effective income tax rates for the total provision for the three months ended June 30, 2011 and 2010 are less than the federal statutory rate primarily due to the impact of nontaxable noncontrolling interests and taxes on foreign operations, partially offset by the effect of state income taxes.

The effective income tax rate for the total provision for the six months ended June 30, 2011 is less than the federal statutory rate primarily due to federal settlements and an international revised assessment, the impact of nontaxable noncontrolling interests and taxes on foreign operations, partially offset by the effect of state income taxes.

The effective income tax rate for the total provision for the six months ended June 30, 2010 is less than the federal statutory rate primarily due to the impact of nontaxable noncontrolling interests, partially offset by the reduction of tax benefits on the Medicare Part D federal subsidy due to enacted health care legislation.

During the first quarter of 2011, we finalized settlements for 1997 through 2008 on certain contested matters with the Internal Revenue Service (IRS) and also received a revised assessment on an international matter. These settlements and revised assessment resulted in a net tax benefit of approximately $124 million during the first quarter of 2011. As a result of these settlements and revised assessment, we have decreased our unrecognized tax benefits by approximately $62 million. In July 2011, we made an $82 million cash payment with respect to the settlements to the IRS and we anticipate making an additional $85 million to $90 million of cash payments to taxing authorities related to these items in 2011.

Notes (Continued)

During the next twelve months, we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of our unrecognized tax benefit.

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(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)	$ 230	$ 188	$ 559	$ (7)
Basic weighted-average shares	588,310	584,414	587,641	584,173
Effect of dilutive securities:				
Nonvested restricted stock units	3,887	2,826	4,005	
Stock options	3,537	3,022	3,501	
Convertible debentures	1,899	2,236	1,950	
Diluted weighted-average shares	597,633	592,498	597,097	584,173
Earnings (loss) per common share from continuing operations:				
Basic	$ .39	$ .32	$ .95	$ (.01)
Diluted	$ .38	$ .31	$ .94	$ (.01)

(1) The three- and six-month periods ended June 30, 2011, include \$.2 million and \$.4 million, respectively, and the three-month period ended June 30, 2010 includes \$.2 million 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 six months ended June 30, 2010, 3.0 million weighted-average nonvested restricted stock units and 3.1 million 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 the six months ended June 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 \$109 million of income for the six months ended June 30, 2010, then these shares would become dilutive.

Notes (Continued)

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

	June 30, 2011	June 30, 2010
Options excluded (millions)	1.0	3.3
Weighted-average exercise price of options excluded	$ 36.47	$ 29.44
Exercise price ranges of options excluded	$ 32.05 - $37.88	$ 21.55 - $40.51
Second quarter weighted-average market price	$ 30.54	$ 21.54

In the second quarter of 2011, an additional 600 thousand options with exercise prices less than the second quarter weighted-average market price were excluded from the computation of weighted-average stock options due to the shares being antidilutive.

Note 7. Employee Benefit Plans

Net periodic benefit expense is as follows:

	Pension Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 10	$ 10	$ 20	$ 18
Interest cost	15	16	32	32
Expected return on plan assets	(19)	(17)	(38)	(35)
Amortization of net actuarial loss	10	8	19	17
Net periodic benefit expense (income)	$ 16	$ 17	$ 33	$ 32

	Other Postretirement Benefits			
	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$	$	$ 1	$ 1
Interest cost	3	4	7	8
Expected return on plan assets	(2)	(2)	(5)	(5)
Amortization of prior service cost (credit)	(2)	(4)	(5)	(7)
Amortization of net actuarial loss	1	1	2	1
Amortization of regulatory asset		1		1
Net periodic benefit expense (income)	$	$	$	$ (1)

During the six months ended June 30, 2011, we contributed $33 million to our pension plans and $7 million to our other postretirement benefit plans. During July 2011, we contributed an additional $30 million to our pension plans. We presently anticipate making additional contributions of approximately $5 million to our pension plans and approximately $8 million to our other postretirement benefit plans in the remainder of 2011.

Notes (Continued)

Note 8. Inventories

	June 30, 2011	December 31, 2010
	(Millions)	
Natural gas liquids and olefins	$ 88	$ 87
Natural gas in underground storage	81	93
Materials, supplies, and other	113	122
	$ 282	$ 302

Note 9. Debt and Banking Arrangements

Credit Facilities

In June 2011, we entered into three new separate five-year senior unsecured revolving credit facility agreements. The replacements of our previous $900 million credit facility and WPZ s $1.75 billion credit facility, as discussed further below, are considered modifications for accounting purposes.

We established a new $900 million unsecured revolving credit facility agreement which replaced our existing unsecured $900 million credit facility agreement that was scheduled to expire May 1, 2012. There were no outstanding borrowings under the existing agreement at the time it was terminated. The credit facility may, under certain conditions, be increased up to an additional $250 million. Significant financial covenants require our ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 4.5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, we are required to maintain a ratio of debt to EBITDA of no greater than 5 to 1. At June 30, 2011, we are in compliance with these financial covenants.

WPZ also established a new $2 billion unsecured revolving credit facility agreement that includes Transco and Northwest Pipeline as co-borrowers that replaced an existing unsecured $1.75 billion credit facility agreement that was scheduled to expire on February 17, 2013. This credit facility is only available to named borrowers. At the closing, WPZ refinanced $300 million outstanding under the existing facility via a non-cash transfer of the obligation to the new credit facility. The new credit facility may, under certain conditions, be increased up to an additional $400 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 the other co-borrowers. Significant financial covenants include:

WPZ s ratio of debt to EBITDA (each as defined in the credit facility) must be no greater than 5 to 1. For the fiscal quarter and the two following fiscal quarters in which one or more acquisitions for a total aggregate purchase price equal to or greater than $50 million has been executed, WPZ is required to maintain a ratio of debt to EBITDA of no greater than 5.5 to 1;

The ratio of debt to capitalization (defined as net worth plus debt) must be no greater than 65 percent for each of Transco and Northwest Pipeline.

At June 30, 2011, WPZ is in compliance with these financial covenants.

WPX entered into a new $1.5 billion unsecured revolving credit facility agreement that will be effective upon meeting certain conditions, including the completion of WPX s initial public offering. This credit facility will only be available to WPX. The new agreement will automatically terminate if the effective date has not occurred on or before November 30, 2011. The credit facility may, under certain conditions, be increased up to an additional $300 million and WPX may also request a swingline loan to obtain same-day funds of up to $125 million under the agreement. Significant financial covenants include:

WPX s PV to debt (each as defined in the credit facility and PV primarily relating to the present value of proved oil and gas reserves) of at least 1.5 to 1;

Notes (Continued)

The ratio of WPX s debt to capitalization (defined as net worth plus debt) must be no greater than 60 percent.

The three new credit agreements contain the following terms and conditions:

Each time funds are borrowed, with the exception of swingline loans under the WPX agreement, the applicable 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. Interest on swingline loans is payable at a rate per annum equal to a fluctuating base rate equal to Citibank N.A s adjusted base rate plus an applicable margin. The applicable borrower is required to pay a commitment fee (currently 0.25 percent for agreements in effect) based on the unused portion of their respective credit facility. The applicable margin and the commitment fee are determined for each borrower by reference to a pricing schedule based on such borrower s senior unsecured long-term debt ratings.

Various covenants limit, among other things, a borrower s and its material subsidiaries ability to grant certain liens supporting indebtedness, a borrower s ability to merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default, make investments and allow any material change in the nature of its business. WPX s credit agreement further limits WPX and its material subsidiaries ability to make certain investments, loans or advances or enter into certain hedging agreements beyond the ordinary course of business.

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

Letters of credit issued and loans outstanding under the credit facility agreements at June 30, 2011, are:

	Expiration	Letters of Credit	Loans
		(Millions)	
$900 million unsecured credit facility (1)	June 3, 2016	$	$
$2 billion WPZ unsecured credit facility (2) (3)	June 3, 2016		350
Bilateral bank agreements for letters of credit		74	
		$ 74	$ 350

(1) $700 million letter of credit capacity.

(2) $1.3 billion letter of credit capacity.

(3) Subsequent to June 30, 2011, WPZ repaid a net $100 million of this loan balance.

Retirements

Utilizing cash on hand, WPZ retired $150 million of 7.5 percent senior unsecured notes that matured on June 15, 2011.

Notes (Continued)

Note 10. Fair Value Measurements

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.

	June 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)							
Assets:								
Energy derivatives	$ 46	$ 352	$ 3	$ 401	$ 96	$ 475	$ 2	$ 573
ARO Trust investments (see Note 11)	40			40	40			40
Available-for-sale equity securities (see Note 11)	27			27				
Total assets	$ 113	$ 352	$ 3	$ 468	$ 136	$ 475	$ 2	$ 613
Liabilities:								
Energy derivatives	$ 41	$ 173	$ 2	$ 216	$ 78	$ 210	$ 1	$ 289
Total liabilities	$ 41	$ 173	$ 2	$ 216	$ 78	$ 210	$ 1	$ 289

Energy derivatives include commodity based exchange-traded contracts and over-the-counter (OTC) contracts. Exchange-traded contracts include futures, swaps, and options. OTC contracts include forwards, swaps and options.

The instruments included in our Level 1 measurements consist of energy derivatives that are exchange-traded, a portfolio of mutual funds, and an investment in marketable equity securities. Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets.

The instruments included in our Level 2 measurements consist primarily of OTC instruments. 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.

The instruments in our Level 3 measurements primarily consist of natural gas index transactions that are used by our Exploration & Production segment to manage physical requirements. 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 because these inputs have a significant impact on the measurement of fair value. As the fair value of natural gas index transactions is primarily driven by the typically nominal differential transacted and the market price, these transactions do not have a material impact on our results of operations or liquidity.

Our energy 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 18 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.

Notes (Continued)

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 between Level 1 and Level 2 occurred during the period ended June 30, 2011 or 2010.

The following table presents a reconciliation of changes in the fair value of our net energy derivatives classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)			
Beginning balance	$	$ 5	$ 1	$ 2
Realized and unrealized gains (losses):				
Included in income (loss) from continuing operations	3	(1)	2	(1)
Included in other comprehensive income (loss)		11	(1)	15
Settlements	(2)	(1)	(2)	(2)
Transfers into Level 3				
Transfers out of Level 3			1	
Ending balance	$ 1	$ 14	$ 1	$ 14
Unrealized gains (losses) included in income (loss) from continuing operations relating to instruments still held at June 30	$ 1	$ (1)	$	$ (1)

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

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, based on the term of the related restriction.

ARO Trust investments: Transco deposits a portion of its collected rates, pursuant to its 2008 rate case settlement, into an external trust (ARO Trust) specifically designated to fund future asset retirement obligations. 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 June 30, 2011 and December 31, 2010, approximately 96 percent and 100 percent, respectively, of our long-term debt was publicly traded. (See Note 9.)

Guarantee: The *guarantee* represented in the following table consists of a guarantee we have provided in the event of nonpayment by our previously owned communications subsidiary, Williams Communications Group (WilTel), on a lease performance obligation. To estimate the fair value of the guarantee, the estimated default rate is determined by obtaining the average cumulative issuer-weighted corporate default rate based on the credit rating of

16

Notes (Continued)

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. Other also includes available-for-sale equity securities. These instruments are reported within *investments* in the Consolidated Balance Sheet and are carried at fair value based upon the publicly traded equity prices.

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 a discussion of the valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	June 30, 2011		December 31, 2010	
Asset (Liability)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
		(Millions)		
Cash and cash equivalents	$ 1,166	$ 1,166	$ 795	$ 795
Restricted cash (current and noncurrent)	$ 29	$ 29	$ 28	$ 28
ARO Trust investments	$ 40	$ 40	$ 40	$ 40
Long-term debt, including current portion (a)	$(9,305)	$(10,325)	$(9,104)	$(9,990)
Guarantees	$ (34)	$ (32)	$ (35)	$ (34)
Other	$ 42	$ 41(b)	$ (23)	$ (25)(b)
Net energy derivatives:				
Energy commodity cash flow hedges	$ 182	$ 182	$ 266	$ 266
Other energy derivatives	$ 3	$ 3	$ 18	$ 18

(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 $1 million and $2 million at June 30, 2011 and December 31, 2010, respectively.

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, crude oil 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 and crude oil 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 and crude oil market prices, we enter into natural gas and crude oil futures contracts, swap agreements, and financial option contracts to mitigate the price risk on forecasted sales of natural gas and crude oil. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Those designated as 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. 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. Those designated as 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:

- Central hub risk: Includes physical and financial derivative exposures to Henry Hub for natural gas, West Texas Intermediate for crude oil, and Mont Belvieu for NGLs;

- Basis risk: Includes physical and financial derivative exposures to the difference in value between the central hub and another specific delivery point;

- Index risk: Includes physical derivative exposure 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.

Fixed price swaps at locations other than the central hub are classified as both central hub risk and basis risk instruments to represent their exposure to overall market conditions (central hub risk) and specific location risk (basis risk).

Notes (Continued)

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of June 30, 2011. NGLs and crude oil are presented in barrels and natural gas is presented in millions of British Thermal Units (MMBtu). 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		**Unit of Measure**	**Central Hub Risk**	**Basis Risk**	**Index Risk**	**Options**
Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(258,680,000)	(258,680,000)		(50,600,000)
Exploration & Production	Risk Management	Barrels	(3,405,500)			
Williams Partners	Risk Management	MMBtu	10,735,000	9,355,000		
Williams Partners	Risk Management	Barrels	(2,960,000)			
Not Designated as Hedging Instruments						
Exploration & Production	Risk Management	MMBtu	(12,940,000)	(15,965,000)	(46,487,263)	
Williams Partners	Risk Management	Barrels	(54,000)			
Midstream Canada & Olefins	Risk Management	Barrels	(50,000)		(144,300)	
Exploration & Production	Other	MMBtu		(8,007,500)		

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.

	June 30, 2011		**December 31, 2010**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
		(Millions)		
Designated as hedging instruments	$ 209	$ 27	$ 288	$ 22
Not designated as hedging instruments:				
Legacy natural gas contracts from former power business	174	173	186	187
All other	18	16	99	80

Total derivatives not designated as hedging instruments	192	189	285	267
Total derivatives	$ 401	$ 216	$ 573	$ 289

Notes (Continued)

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

	Three months ended June 30,		Six months ended June 30,		Classification
	2011	2010	2011	2010	
	(Millions)		(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ 75	$ 32	$ 52	$ 310	AOCI
Net gain (loss) reclassified from accumulated other income (effective portion)	$ 63	$ 100	$ 138	$ 125	Revenues or Costs and Operating Expenses
Gain (loss) recognized in income (ineffective portion)	$	$ (2)	$	$ 3	Revenues or Costs and Operating Expenses

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 June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	(Millions)		(Millions)	
Revenues	$ 2	$ (15)	$ 4	$ 11
Costs and operating expenses		7		7
Net gain (loss)	$ 2	$ (22)	$ 4	$ 4

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*.

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 June 30, 2011, we did not have any collateral 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 $22 million, which includes a reduction of significantly less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2010, we had collateral totaling $8 million posted to

20

Notes (Continued)
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 $36 million, which included a reduction of less than $1 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 $22 million and $29 million at June 30, 2011 and December 31, 2010, respectively.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI 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 June 30, 2011, we have hedged portions of future cash flows associated with anticipated energy commodity purchases and sales for up to two years. Based on recorded values at June 30, 2011, $97 million of net gains (net of income tax provision of $58 million) will be reclassified into earnings within the next year. These recorded values are based on market prices of the commodities as of June 30, 2011. 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

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.

We have provided a guarantee in the event of nonpayment by our previously owned communications subsidiary, WilTel, on a certain lease performance obligation that extends through 2042. The maximum potential exposure is approximately $38 million at June 30, 2011 and $39 million at December 31, 2010. Our exposure declines systematically throughout the remaining term of WilTel s obligation. The carrying value of the guarantee included in *accrued liabilities* on the Consolidated Balance Sheet is $34 million at June 30, 2011 and $35 million at December 31, 2010.

At June 30, 2011, 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 an 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 June 30, 2011, is summarized as follows:

Notes (Continued)

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 3	$ 3
Energy marketers and traders		112
Financial institutions	286	286
	$ 289	401
Credit reserves		
Gross credit exposure from derivatives		$ 401

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 June 30, 2011, excluding collateral support discussed below, is summarized as follows:

Notes (Continued)

Counterparty Type	**Investment Grade(a)**	**Total**
	(Millions)	
Gas and electric utilities	$ 2	$ 2
Energy marketers and traders		1
Financial institutions	204	204
	$ 206	207
Credit reserves		
Net credit exposure from derivatives		$ 207

(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.

Our ten largest net counterparty positions represent approximately 98 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Included within this group are counterparty positions, representing 86 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 June 30, 2011, the designated collateral agent is not required to hold any collateral support on our behalf under Exploration & Production s hedging facility. We hold collateral support, which may include cash or letters of credit, of $4 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 Federal Energy Regulatory Commission (FERC). 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.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We are currently in settlement negotiations with certain California utilities aimed at eliminating or substantially reducing this exposure. If successful, and subject to a final true-up mechanism, the settlement agreement would also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement would resolve most, if not all, of our legal issues arising from the 2000-2001 California Energy Crisis. With respect to these matters, amounts accrued are not material to our financial position.

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

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 natural gas in those states. These cases were transferred to the federal

Notes (Continued)

court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs lack of standing. In 2009, the court denied the plaintiffs request for reconsideration of the Colorado dismissal and entered judgment in our favor. The court s order became final on July 18, 2011, and we expect that the Colorado plaintiffs will appeal.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs class certification motion as moot. On July 22, 2011, the plaintiffs filed their notice of appeal with the Nevada district court. Because of the uncertainty around these current pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time. However, it is reasonably possible that the ultimate resolution of these items could result in future charges that may be material to our results of operations.

Environmental Matters

Continuing operations

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyl, mercury contamination, and other hazardous substances. These activities have involved the U.S. Environmental Protection Agency (EPA), various state environmental authorities and identification as a potentially responsible party at various Superfund waste disposal sites. At June 30, 2011, we have accrued liabilities of $11 million for these costs. We expect that these costs will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At June 30, 2011, we have accrued liabilities totaling $8 million for these costs.

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. Tentative settlement was reached in first-quarter 2011.

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 notices of violation alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted our response denying the allegations in June 2008. In May 2011, we provided additional information to the EPA pertaining to these compressor stations in response to a request they had made in February 2011. In August 2010, the EPA requested, and our Transco subsidiary provided, similar information for a compressor station in Maryland.

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 relate to the operations of the assets and businesses described below.

Former agricultural fertilizer and chemical operations and former retail petroleum and refining operations;

Former petroleum products and natural gas pipelines;

Discontinued petroleum refining facilities;

Former exploration and production and mining operations.

At June 30, 2011, we have accrued environmental liabilities of $30 million related to these matters.

Notes (Continued)

Actual costs 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. Any incremental amount cannot be reasonably estimated at this time.

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.

Environmental matters general

The EPA and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, and one hour nitrogen dioxide emission limits. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Other Legal Matters

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. On February 17, 2011, the Texas Court of Appeals upheld the dismissals of the tort and punitive damages claims and reversed and remanded the contract claim and attorney fee claims for further proceedings. The appellate court ruling is subject to a potential appeal to the Texas Supreme Court. If the appellate court judgment is upheld, our remaining liability could be 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 District Court, Garfield County Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of natural gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify as a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments resulting from calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement

Notes (Continued)
defined the class members for class certification, reserved two claims for court resolution, resolved all other class claims relating to past calculation of royalty and overriding royalty payments, and established certain rules to govern future royalty and overriding royalty payments. This settlement resolved all claims relating to past withholding for ad valorem tax payments and established a procedure for refunds of any such excess withholding in the future. The first reserved claim is whether we are entitled to deduct in our calculation of royalty payments a portion of the costs we incur beyond the tailgates of the treating or processing plants for mainline pipeline transportation. We received a favorable ruling on our motion for summary judgment on the first reserved claim. Plaintiffs appealed that ruling and the Colorado Court of Appeals found in our favor in April 2011. In June 2011, Plaintiffs filed a Petition for Certiorari with the Colorado Supreme Court. We anticipate that court will issue a decision on whether to grant further review later in 2011 or early in 2012. The second reserved claim relates to whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are thus entitled to deduct a proportionate share of transportation costs in calculating royalty payments. We anticipate trial on the second reserved claim following resolution of the first reserved claim. We believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law. At this time, the plaintiffs have not provided us a sufficient framework to calculate an estimated range of exposure related to their claims. However, it is reasonably possible that the ultimate resolution of this item could result in a future charge that may be material to our results of operations.

Other producers have been in litigation or discussions with a federal regulatory agency and a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, 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 an 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. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (ONRR) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The ONRR s guidance provides its view as to how much of a producer s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states, but such guidelines are expected in the future. However, the timing of receipt of the necessary guidelines is uncertain. In addition, these interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and will vary based upon the ONRR s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. From January 2004 through December 2010, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $55 million. Correspondence in 2009 with the ONRR s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions which we believe have been consistent with the requirements. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments and the effect could be material to our results of operations.

Other

In 2003, we entered into an agreement to sublease certain underground storage facilities to Liberty Gas Storage (Liberty). We have asserted claims against Liberty for prematurely terminating the sublease and for damage caused to the facilities. In February 2011, Liberty asserted a counterclaim for costs in excess of $200 million associated with its use of the facilities. Due to the lack of information currently available, we are unable to evaluate the merits of the counterclaim and determine the amount of any possible liability.

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

Notes (Continued)

generally relate to breach of warranties, tax, historic litigation, personal injury, property damage, environmental matters, right of way and other representations that we have provided.

At June 30, 2011, 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

Our reporting segments are Williams Partners, Exploration & Production and Midstream Canada & Olefins. All remaining business activities are included in Other. (See Note 2.)

Performance Measurement

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

Midstream Canada & Olefins commodity purchases (primarily for shrink, feedstock and NGL and olefin marketing activities), depreciation and operation and maintenance expenses.

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 and *total assets* by reporting segment.

	Williams Partners	**Exploration & Production**	**Midstream Canada & Olefins**	**Other**	**Eliminations**	**Total**
			(Millions)			
Three months ended June 30, 2011						
Segment revenues:						
External	$ 1,557	$ 762	$ 345	$ 5	$	$ 2,669
Internal	114	219	2	2	(337)	
Total revenues	$ 1,671	$ 981	$ 347	$ 7	$ (337)	$ 2,669
Segment profit (loss)	$ 471	$ 94	$ 72	$ 2	$	$ 639
Less equity earnings (losses)	36	5		4		45
Segment operating income (loss)	$ 435	$ 89	$ 72	$ (2)	$	594
General corporate expenses						(47)
Total operating income (loss)						$ 547
Three months ended June 30, 2010						
Segment revenues:						
External	$ 1,307	$ 726	$ 254	$ 2	$	$ 2,289
Internal	93	175	3	3	(274)	
Total revenues	$ 1,400	$ 901	$ 257	$ 5	$ (274)	$ 2,289
Segment profit (loss)	$ 361	$ 73	$ 61	$ 18	$	$ 513
Less:						
Equity earnings (losses)	27	5		7		39
Income (loss) from investments				13		13
Segment operating income (loss)	$ 334	$ 68	$ 61	$ (2)	$	461
General corporate expenses						(45)

Total operating income (loss)	$ 416

&n