Williams Partners L.P.
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 1-32599

WILLIAMS PARTNERS L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	20-2485124
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER TULSA, OKLAHOMA	74172-0172
(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). Yes þ No o

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

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

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

The registrant had 279,995,437 common units outstanding as of October 25, 2010.

Williams Partners L.P.
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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.

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 statements are based on management s beli 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;

Cash flow from operations or results of operations;

The levels of cash distributions to unitholders;

Seasonality of certain business segments;

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. Limited partner units are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the risk factors discussed below in addition to the other information in this report. If any of the following risks were actually to occur, our business, results of operations and financial condition could be materially adversely affected. In that case, we might not be able to pay distributions on our common units, the trading price of our common units could decline, and unitholders could lose all or part of their investment. Many of the factors that will

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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:

- Whether we have sufficient cash from operations to enable us to pay cash distributions following establishment of cash reserves and payment of fees and expenses, including payments to our general partner;
- Availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and the availability and cost of capital;
- Inflation, interest rates 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 allocated costs for defined benefit pension plans and other postretirement benefit plans sponsored by our affiliates;
- Changes in maintenance and construction costs;
- Changes in the current geopolitical situation;
- Our exposure to the credit risks 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; and
- 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, 2009, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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PART I FINANCIAL INFORMATION
Williams Partners L.P.
Consolidated Statement of Income
(Unaudited)

	Three months ended September 30, 2010	Three months ended September 30, 2009*	Nine months ended September 30, 2010	Nine months ended September 30, 2009*
	(Millions, except per-unit amounts)			
Revenues:				
Gas Pipeline	$ 409	$ 380	$ 1,196	$ 1,202
Midstream Gas & Liquids	883	802	2,921	2,023
Intercompany eliminations	(1)	(1)	(1)	(6)
Total revenues	1,291	1,181	4,116	3,219
Segment costs and expenses:				
Costs and operating expenses	908	793	2,909	2,174
Selling, general and administrative expenses	67	72	194	213
Other income net	(3)	(1)	(13)	(1)
Segment costs and expenses	972	864	3,090	2,386
General corporate expenses	29	26	91	77
Operating income:				
Gas Pipeline	151	138	449	449
Midstream Gas & Liquids	168	179	577	384
General corporate expenses	(29)	(26)	(91)	(77)
Total operating income	290	291	935	756
Equity earnings	24	30	77	51
Interest accrued third-party	(103)	(51)	(285)	(153)
Interest accrued affiliate		(9)	(1)	(39)
Interest capitalized	7	10	26	41
Interest income		5	3	16
Other income net	9	4	10	9
Income before income taxes	227	280	765	681
Provision for income taxes	1	1	1	4
Net income	226	279	764	677
Less: Net income attributable to noncontrolling interests	5	7	16	20
Net income attributable to controlling interests	$ 221	$ 272	$ 748	$ 657

Allocation of net income for calculation of earnings per common unit:								
Net income attributable to controlling interests	$	221	$	272	$	748	$	657
Allocation of net income to general partner and Class C units		58		217		393		557
Allocation of net income to common units	$	163	$	55	$	355	$	100
Basic and diluted net income per common unit	$	0.63	$	1.04	$	1.87	$	1.88
Weighted average number of common units outstanding		260,507,501(a)		52,777,452		190,448,384(a)		52,777,452

(a) Calculated as discussed in Note 2.

* Recast as discussed in Note 1.

See accompanying notes.

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Williams Partners L.P.
Consolidated Balance Sheet
(Unaudited)

	September 30, 2010	December 31, 2009
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 92	$ 153
Accounts receivable:		
Trade	341	381
Affiliate	5	6
Inventories	160	129
Regulatory assets	63	77
Prepaid expense	41	26
Other current assets	35	49
Total current assets	737	821
Investments	1,020	593
Gross property, plant and equipment	15,812	15,416
Less accumulated depreciation	(5,508)	(5,191)
Property, plant and equipment net	10,304	10,225
Regulatory assets, deferred charges and other	410	345
Total assets	$ 12,471	$ 11,984
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 297	$ 356
Affiliate	146	80
Accrued interest	110	49
Other accrued liabilities	163	136
Long-term debt due within one year	458	15
Total current liabilities	1,174	636
Long-term debt	5,765	2,981
Asset retirement obligations	447	477
Regulatory liabilities, deferred income and other	281	263
Contingent liabilities and commitments (Note 8) Equity:		
Common units (278,607,937 units outstanding at September 30, 2010 and 52,777,452 units outstanding at December 31, 2009)	6,111	1,631
General partner	(1,297)	5,647
Accumulated other comprehensive income (loss)	(10)	2
Noncontrolling interests in consolidated subsidiaries		347

Total equity	4,804	7,627
Total liabilities and equity	$ 12,471	$ 11,984

See accompanying notes.

Williams Partners L.P.
Consolidated Statement of Changes in Equity
(Unaudited)

	Williams Partners L.P.					
	Limited Partners		General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
	Common	Class C				
				(Millions)		
Balance January 1, 2010	$ 1,631	$	$ 5,647	$ 2	$ 347	$ 7,627
Comprehensive income:						
Net income	339	156	253		16	764
Other comprehensive loss:						
Net unrealized change in cash flow hedges				(12)		(12)
Total other comprehensive loss						(12)
Total comprehensive income						752
Cash distributions	(240)	(87)	(83)			(410)
Dividends paid to noncontrolling interests					(18)	(18)
Issuance of units (203,000,000 Class C units)		6,946	(6,946)			
Distributions to The Williams Companies, Inc. net		(3,357)	(188)			(3,545)
Conversion of Class C units to Common (203,000,000 units)	3,658	(3,658)				
Issuance of units due to Williams Pipeline Partners L.P. merger (13,580,485 common units)	343				(343)	
Issuance of units to public (9,250,000 common units)	380					380
Contributions from General Partner			20			20
Other					(2)	(2)
Balance September 30, 2010	$ 6,111	$	$ (1,297)	$ (10)	$	$ 4,804

See accompanying notes.

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Williams Partners L.P.
Consolidated Statement of Cash Flows
(Unaudited)

	Nine months ended September 30,	
	2010	2009*
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 764	$ 677
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	403	394
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	40	(74)
Inventories	(31)	15
Other assets and deferred charges	15	20
Accounts payable	(4)	(39)
Accrued liabilities	85	(48)
Affiliates net	67	(27)
Other, including changes in noncurrent assets and liabilities	14	123
Net cash provided by operating activities	1,353	1,041
FINANCING ACTIVITIES:		
Proceeds from long-term debt	4,179	
Payments of long-term debt	(953)	
Payment of debt issuance costs	(62)	
Proceeds from sales of common units	380	
General Partner contributions	20	
Dividends paid to noncontrolling interests	(18)	(18)
Distributions to limited partners and general partner	(410)	(110)
Distributions to The Williams Companies, Inc. net	(119)	(184)
Other net	(6)	12
Net cash provided (used) by financing activities	3,011	(300)
INVESTING ACTIVITIES:		
Purchase of Contributed Entities	(3,426)	
Property, plant and equipment:		
Capital expenditures	(570)	(624)
Net proceeds from dispositions	35	1
Changes in notes receivable from parent		(84)
Purchase of investments	(450)	(123)
Distribution received from Gulfstream Natural Gas System, L.L.C.		73
Other net	(14)	(7)
Net cash used by investing activities	(4,425)	(764)

Decrease in cash and cash equivalents		(61)		(23)
Cash and cash equivalents at beginning of period		153		133
Cash and cash equivalents at end of period	$	92	$	110

* Recast as discussed in Note 1.

See accompanying notes.

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Williams Partners L.P.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1. Organization, Basis of Presentation, and Description of Business

Organization

Unless the context clearly indicates otherwise, references in this report to we, our, us or similar language refer to Williams Partners L.P. and its subsidiaries.

We are a publicly traded Delaware limited partnership. Williams Partners GP LLC, a Delaware limited liability company wholly owned by The Williams Companies, Inc. (Williams), serves as our general partner. Williams currently owns an approximate 75 percent limited partner interest, a 2 percent general partner interest and incentive distribution rights (IDRs) in us. All of our activities are conducted through Williams Partners Operating LLC (OLLC), an operating limited liability company (wholly owned by us).

The 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 for the year ended December 31, 2009 in Exhibit 99.1 of our Form 8-K, dated May 12, 2010. The accompanying interim consolidated financial statements include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our financial position at September 30, 2010, results of operations for the three and nine months ended September 30, 2010 and 2009, changes in equity for the nine months ended September 30, 2010, and cash flows for the nine months ended September 30, 2010 and 2009. We eliminated all intercompany transactions and reclassified certain amounts to conform to the current classifications.

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 May 24, 2010, we and Williams Pipeline Partners L.P. (WMZ) entered into a merger agreement that was consummated on August 31, 2010. All of WMZ s common units not held by its general partner were exchanged at a ratio of 0.7584 of our limited partner units for each WMZ limited partner unit, resulting in the issuance of 13,580,485 of our common units. All WMZ common and subordinated units have been extinguished and WMZ is wholly owned by us. WMZ has been delisted and is no longer publicly traded. As a result of the merger, we now own 100 percent of Northwest Pipeline GP (Northwest Pipeline).

Basis of Presentation

On February 17, 2010, we closed a transaction (the Dropdown) with our general partner, our operating company and certain subsidiaries of and including Williams, pursuant to which Williams contributed to us the ownership interests in the entities that made up its Gas Pipeline and Midstream Gas & Liquids (Midstream) businesses to the extent not already owned by us, including Williams limited and general partner interests in WMZ, but excluding its Canadian, Venezuelan and olefins operations, and 25.5 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream), collectively defined as the Contributed Entities.

This contribution was made in exchange for aggregate consideration of:

- $3.5 billion in cash, less certain expenses incurred by us and other post-closing adjustments, which we financed by issuing $3.5 billion of senior unsecured notes (see Note 4).

- 203 million of our Class C limited partnership units, which automatically converted into our common limited partnership units on May 10, 2010.

- An increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest.

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Notes (Continued)

These transactions are reflected in these consolidated financial statements. Because the acquired entities were affiliates of Williams at the time of the acquisition, this transaction is accounted for as a combination of entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired entities are combined with ours at their historical amounts. The effect of recasting our financial statements to account for this common control transaction increased net income $223 million and $576 million for the three and nine months ended September 30, 2009, respectively. This acquisition did not impact historical earnings per limited partner unit as pre-acquisition earnings of the Contributed Entities were allocated to our general partner.

Description of Business

Our operations are located in the United States and are organized into the following reporting segments: Gas Pipeline and Midstream.

Gas Pipeline includes Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline, which own and operates a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of natural gas. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 million Dth per day of natural gas.

Midstream includes our natural gas gathering, treating and processing businesses and has a primary service area concentrated in major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico and Pennsylvania. Midstream s primary businesses natural gas gathering, treating and processing; natural gas liquids (NGL) fractionation, storage and transportation; and oil transportation fall within the middle of the process of taking raw natural gas and crude oil from the producing fields to the consumers.

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Notes (Continued)

Note 2. Allocation of Net Income and Distributions

The allocation of net income among our general partner, limited partners, and noncontrolling interests for the three and nine months ended September 30, 2010 and 2009, is as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)			
Allocation of net income to general partner:				
Net income	$ 226	$ 279	$ 764	$ 677
Net income applicable to pre-partnership operations allocated to general partner		(216)	(163)	(556)
Net income applicable to noncontrolling interests	(5)	(7)	(16)	(20)
Net reimbursable costs charged directly to general partner			(4)	1
Income subject to 2% allocation of general partner interest	221	56	581	102
General partner s share of net income	2.0%	2.0%	2.0%	2.0%
General partner s allocated share of net income before items directly allocable to general partner interest	4	1	11	2
Incentive distributions paid to general partner*	45		75	7
Charges allocated directly to general partner			4	(1)
Pre-partnership net income allocated to general partner interest		216	163	556
Net income allocated to general partner	$ 49	$ 217	$ 253	$ 564
Net income	$ 226	$ 279	$ 764	$ 677
Net income allocated to general partner	49	217	253	564
Net income allocated to Class C limited partners			156	
Net income allocated to noncontrolling interests	5	7	16	20
Net income allocated to common limited partners	$ 172	$ 55	$ 339	$ 93

* In the calculation of basic and diluted net income per limited partner unit, the net income allocated to the general partner includes IDRs pertaining to the

current reporting period, but paid in the subsequent period. The net income allocated to the general partner s capital account reflects IDRs paid during the current reporting period.

The *Charges allocated directly to general partner* amounts represent the net of both income and expense items. Under the terms of an omnibus agreement, we are reimbursed by our general partner for certain expense items and are required to distribute certain income items to our general partner.

For purposes of calculating the year-to-date 2010 basic and diluted net income per common unit, the weighted average number of common units outstanding are calculated considering Class C units as common units effective April 1, 2010, and net income allocated to the Class C units prior to that date is based on the distributed earnings paid to the Class C units for first-quarter 2010. For the allocation of 2010 net income for the *Consolidated Statement of Changes in Equity*, net income was allocated based on the number of days the Class C units were outstanding as Class C units during 2010.

Total comprehensive income for the three months ended September 30, 2010 and 2009 is $203 million and $279 million, respectively, and for the nine months ended September 30, 2010 and 2009 is $752 million and $676 million, respectively. The difference between total comprehensive income and net income for all periods is due to net unrealized changes in cash flow hedges.

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Notes (Continued)

We paid or have authorized payment of the following partnership cash distributions during 2009 and 2010 (in millions, except for per unit amounts):

Payment Date	Per Unit Distribution	Common Units	Class C Units	2%	Incentive Distribution Rights	Total Cash Distribution
2/13/2009	$ 0.6350	$ 33	$	$ 1	$ 8	$ 42
5/15/2009	$ 0.6350	$ 33	$	$ 1	$	$ 34
8/14/2009	$ 0.6350	$ 33	$	$ 1	$	$ 34
11/13/2009	$ 0.6350	$ 33	$	$ 1	$	$ 34
2/12/2010	$ 0.6350	$ 33	$	$ 1	$	$ 34
5/14/2010 (a)	$ 0.6575	$ 35	$ 87	$ 3	$ 30	$ 155
8/13/2010	$ 0.6725	$ 172	$	$ 4	$ 45	$ 221
11/12/2010 (b)	$ 0.6875	$ 192	$	$ 5	$ 53	$ 250

(a) Distributions on the Class C units and the additional general partner units issued in connection with the closing of the Dropdown, as well as the related incentive distribution rights payment, were prorated to reflect the fact that they were not outstanding during the first full quarter period.

(b) The Board of Directors of our general partner declared this cash distribution on October 25, 2010, to be paid on November 12, 2010, to unitholders of record at the close of business on November 5, 2010.

Note 3. Inventories

	September 30, 2010	December 31, 2009
	(Millions)	
Natural gas liquids	$ 53	$ 44
Natural gas in underground storage	36	20
Materials, supplies, and other	71	65
	$ 160	$ 129

Note 4. Debt and Banking Arrangements

Long-Term Debt

As of September 30, 2010, our debt is unsecured with a weighted-average interest rate of 6.1 percent, payable through 2040. Interest rates range from 3.8 percent to 9.0 percent. Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, make certain distributions, repurchase equity, and incur additional debt.

Revolving Credit and Letter of Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion three-year senior unsecured revolving credit facility (Credit Facility) with Transco and Northwest Pipeline as co-borrowers. This Credit Facility replaced our 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 Dropdown. At the closing, we utilized $250 million of the Credit Facility to repay the outstanding term loan. During the third quarter of 2010, we 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, the outstanding balance was reduced to zero, primarily with proceeds from our equity offering. (See Note 5.) As of September 30, 2010, no loans are outstanding under the Credit Facility.

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Notes (Continued)

The Credit Facility expires February 17, 2013, and may, under certain conditions, be increased by up to an additional $250 million. The full amount of the Credit Facility is available to us 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. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) Citibank N.A. s publicly announced base rate, and (iii) one-month LIBOR plus 1.0 percent. We are 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:

- Our 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.

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 the loans of the defaulting borrower under the Credit Facility and exercise other rights and remedies.

Issuances

In connection with the Dropdown, we 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, we 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, we 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)

Note 5. Partners Capital

On August 31, 2010, the WMZ unitholders approved the merger between WMZ and us (see Note 1). As a result of the merger, effective September 1, 2010, WMZ unitholders, other than its general partner, received 0.7584 WPZ common units for each WMZ common unit they owned at the effective time of the merger, for a total issuance of 13,580,485 common units.

On September 28, 2010, we completed an equity issuance of 9,250,000 common units representing limited partner interests in us at a price of $42.40 per unit. The proceeds of approximately $380 million, net of the underwriters discount and fees of approximately $12 million were used to repay borrowings incurred to fund a portion of our additional $424 million investment in OPPL. This additional investment increases our ownership interest in OPPL to 50 percent, which is included in our Midstream segment and is accounted for using the equity method of accounting.

On October 8, 2010, we sold an additional 1,387,500 common units to the underwriters upon the underwriters exercise of their option to purchase additional common units pursuant to our common unit offering in September 2010. The proceeds of $57 million, net of the underwriters discount and fees of approximately $2 million were used for general corporate purposes.

Note 6. 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. The instruments included in our Level 2 measurements consist primarily of over-the-counter instruments such as natural gas forward contracts and swaps.

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

Notes (Continued)

The following table 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:								
ARO Trust Investments (see Note 7)	$ 37	$	$	$ 37	$ 22	$	$	$ 22
Energy derivatives		1	1	2			2	2
Total assets	$ 37	$ 1	$ 1	$ 39	$ 22	$	$ 2	$ 24
Liabilities:								
Energy derivatives	$	$ 6	$ 2	$ 8	$	$	$ 2	$ 2
Total liabilities	$	$ 6	$ 2	$ 8	$	$	$ 2	$ 2

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.

Forward and swap contracts included in Level 2 are valued using an income approach including present value techniques. Significant inputs into our Level 2 valuations include commodity prices 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 tenure of our derivatives portfolio is relatively short with all of our derivatives expiring by December 31, 2010. 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.

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. Certain inputs into the model are generally observable, such as interest rates, whereas natural gas liquids commodity prices are considered unobservable. The instruments included in Level 3 consist primarily of natural gas liquids swaps and forward contracts.

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 September 30, 2010. The following tables present a reconciliation of changes in the fair value of our net energy derivatives classified as Level 3 in the fair value hierarchy.

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Notes (Continued)

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Net Energy Derivatives Three months ended September 30,		Net Energy Derivatives Nine months ended September 30,	
	2010	2009	2010	2009
	(Millions)		(Millions)	
Beginning balance	$ 20	$ 5	$	$ 1
Realized and unrealized gains (losses):				
Included in net income	8		10	4
Included in other comprehensive income (loss)	(20)		1	
Purchases, issuances, and settlements	(9)	(2)	(12)	(2)
Transfers into Level 3				
Transfers out of Level 3				
Ending balance	$ (1)	$ 3	$ (1)	$ 3
Unrealized gains (losses) included in net income relating to instruments still held at September 30	$	$	$	$ 3

Realized and unrealized gains (losses) included in *net income* for the above periods are reported in *revenues* in our Consolidated Statement of Income.

For the periods ended September 30, 2010 and 2009, there were no assets or liabilities measured at fair value on a nonrecurring basis.

Note 7. Financial Instruments, Derivatives and Concentrations 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: The carrying amounts reported in the *Consolidated Balance Sheet* approximate fair value due to the short-term maturity of these instruments.

ARO Trust Investments: Pursuant to its 2008 rate case settlement, Transco deposits a portion of its collected rates into an external trust (ARO Trust) that is 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 *regulatory assets, deferred charges and other* 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 valued 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 91 percent, respectively, of our long-term debt was publicly traded. (See Note 4.)

Other: Includes current and noncurrent notes receivable.

Energy derivatives: Energy derivatives include forwards and swaps. These are carried at fair value in *other current assets* and *other accrued liabilities* in the *Consolidated Balance Sheet.* See Note 6 for discussion of valuation of our energy derivatives.

Notes (Continued)

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	$ 92	$ 92	$ 153	$ 153
ARO Trust Investments	37	37	22	22
Long-term debt, including current portion	(6,223)	(6,958)	(2,996)	(3,194)
Other			3	3
Net energy derivatives:				
Energy commodity cash flow hedges affiliate	(7)	(7)	(2)	(2)
Other energy derivatives	1	1	2	2

Energy Commodity Derivatives

Risk management activities

We are exposed to market risk from changes in energy commodity prices within our operations. We may utilize derivatives to manage our exposure to the variability in expected future cash flows from forecasted purchases of natural gas and forecasted sales of 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 sell NGL volumes received as compensation for certain processing services at different locations throughout the United States. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs. 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 market prices, we may enter into NGL or natural gas swap agreements, financial or physical forward contracts, and financial option contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas. 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.

Volumes

Our energy commodity derivatives are comprised of both contracts to purchase commodities (long positions) and contracts to sell commodities (short positions). Derivative transactions are categorized into two 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.

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.

Derivative Notional Volumes		Measurement	Fixed Price	Basis
Designated as Hedging Instruments				
Midstream	Risk Management	MMBtu	6,365,000	4,305,000
Midstream	Risk Management	Gallons	(69,636,000)	
Not Designated as Hedging Instruments				
Midstream	Risk Management	Gallons	(3,360,000)	

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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 included in *other current assets* and *other accrued liabilities* in our *Consolidated Balance Sheet*. 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 by December 31, 2010.

	September 30, 2010		December 31, 2009	
	Assets	Liabilities	Assets	Liabilities
	(Millions)		(Millions)	
Designated as hedging instruments	$ 1	$ 8	$	$ 2
Not designated as hedging instruments	1		2	
Total derivatives	$ 2	$ 8	$ 2	$ 2

The following table presents 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 loss recognized in other comprehensive income (effective portion)	$ (20)	$	$ (6)	$	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$ 4	$	$	$	Revenues
Gain (loss) recognized in income (ineffective portion)	$	$	$	$	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. As of September 30, 2010, we have hedged portions of future cash flows associated with anticipated NGL sales and natural gas purchases through December 31, 2010. Based on recorded values at September 30, 2010, net losses to be reclassified into earnings by December 31, 2010, are $7 million. 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 by December 31, 2010, will likely differ from these values. These gains or losses will offset net losses or gains that will be realized in earnings from previous unfavorable or favorable market movements associated with underlying hedged transactions.

We recognized losses of less than $1 million and gains of $3 million in *revenues* for the nine months ended September 30, 2010, and 2009, respectively, on our energy commodity derivatives not designated as hedging instruments.

The cash flow impact of our derivative activities is presented in the *Consolidated Statement of Cash Flows* as *changes in other assets and deferred charges* and *changes in accrued liabilities*.

Credit-risk-related features

Our financial swap contracts are with Williams Gas Marketing, Inc., and the derivative contracts not designated as cash flow hedging instruments are primarily physical commodity sale contracts. These agreements do not contain any provisions that require us to post collateral related to net liability positions.

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Notes (Continued)

Guarantees

In addition to the guarantees and payment obligations discussed in Note 8, we have issued guarantees and other similar arrangements as discussed below.

We are required by our revolving credit agreement 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.

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.

Note 8. Contingent Liabilities

Environmental Matters

Since 1989, Transco 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, Northwest Pipeline 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 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 a new air quality standard 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 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.

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Notes (Continued)

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.

In September 2007, the EPA requested, and Transco 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 violations (NOVs) alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted its response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, Transco submitted the requested information. On August 20, 2010, the EPA requested, and Transco later provided, similar information for a compressor station in Maryland.

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 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.

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.

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.

Rate Matters

On August 31, 2006, Transco submitted to the Federal Energy Regulatory Commission (FERC) a general rate filing (Docket No. RP06-569) principally designed to recover increased costs. The rates became effective March 1, 2007, subject to refund and the outcome of a hearing. All issues in this proceeding except one have been resolved by settlement.

The one issue reserved for litigation or further settlement relates to Transco s proposal to change the design of the rates for service under one of its storage rate schedules, which was implemented subject to refund on March 1, 2007. A hearing on that issue was held before a FERC Administrative Law Judge (ALJ) in July 2008. In November 2008, the ALJ issued an initial decision in which he determined that Transco s proposed incremental rate design is unjust and unreasonable. On January 21, 2010, the FERC reversed the ALJ s initial decision, and approved our proposed incremental rate design. Certain parties have sought rehearing of the FERC s order.

Safety Matters

The United States Department of Transportation Pipeline and Hazardous Materials Safety Administration rules implementing the Pipeline Safety Improvement Act of 2002 require pipeline operators to implement integrity management programs, including more frequent inspections and other safeguards in areas where the potential consequences of pipeline accidents pose the greatest risk to people and property. In accordance with the final rule, Transco and Northwest Pipeline developed Integrity Management Plans, identified high consequence areas, completed baseline assessment plans, and are on schedule to complete the required assessments within specified timeframes. Currently, Transco and Northwest Pipeline estimate that the cost to perform required assessments and

Notes (Continued)
remediation will be primarily capital and range between $120 and $180 million, and between $80 and $95 million, respectively, over the remaining assessment period of 2010 through 2012. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through their respective rates.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, we were named, along with other subsidiaries of Williams, 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.

Other

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 9. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge.

Performance Measurement

We currently evaluate segment operating performance based on *segment profit* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses,* and *equity earnings*. 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:

- Gas Pipeline depreciation and operation and maintenance expenses;
- Midstream commodity purchases (primarily for NGL and crude marketing, shrink and fuel), depreciation, and operation and maintenance expenses.

Notes (Continued)

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

	Gas Pipeline	Midstream	Eliminations	Total
		(Millions)		
Three months ended September 30, 2010				
Segment revenues:				
External	$ 408	$ 883	$	$ 1,291
Internal	1		(1)	
Total revenues	$ 409	$ 883	$ (1)	$ 1,291
Segment profit	$ 161	$ 182	$	$ 343
Less equity earnings	10	14		24
Segment operating income	$ 151	$ 168	$	319
General corporate expenses				(29)
Total operating income				$ 290
Three months ended September 30, 2009*				
Segment revenues:				
External	$ 380	$ 801	$	$ 1,181
Internal		1	(1)	
Total revenues	$ 380	$ 802	$ (1)	$ 1,181
Segment profit	$ 148	$ 199	$	$ 347
Less equity earnings	10	20		30
Segment operating income	$ 138	$ 179	$	317
General corporate expenses				(26)
Total operating income				$ 291

	Gas Pipeline	Midstream	Eliminations	Total
		(Millions)		
Nine months ended September 30, 2010				
Segment revenues:				
External	$ 1,195	$ 2,921	$	$ 4,116
Internal	1		(1)	

Total revenues	$	1,196	$ 2,921	$	(1)	$ 4,116
Segment profit	$	478	$ 625	$		$ 1,103
Less equity earnings		29	48			77
Segment operating income	$	449	$ 577	$		1,026
General corporate expenses						(91)
Total operating income						$ 935
Nine months ended September 30, 2009*						
Segment revenues:						
External	$	1,202	$ 2,017	$		$ 3,219
Internal			6		(6)	
Total revenues	$	1,202	$ 2,023	$	(6)	$ 3,219
Segment profit	$	475	$ 409	$		$ 884
Less equity earnings		26	25			51
Segment operating income	$	449	$ 384	$		833
General corporate expenses						(77)
Total operating income						$ 756

* Recast as discussed in Note 1.

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Notes (Continued)

Note 10. Subsequent Event

On October 26, 2010 we agreed to acquire certain gathering and processing assets in Colorado s Piceance Basin from our general partner, Williams, 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 we expect to fund using our credit facility and/or debt, approximately 1.8 million common units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest.

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

Recent Developments

The Dropdown

On February 17, 2010, we closed a transaction with our general partner, our operating company, The Williams Companies, Inc. (Williams) and certain subsidiaries of Williams, pursuant to which Williams contributed to us the ownership interests in the entities that made up Williams Gas Pipeline and Midstream Gas & Liquids (Midstream) businesses to the extent not already owned by us, including Williams limited and general partner interests in Williams Pipeline Partners L.P. (WMZ), but excluding Williams Canadian, Venezuelan, and olefin operations and 25.5 percent of Gulfstream Natural Gas System, L.L.C. (Gulfstream). Such entities are hereafter referred to as the Contributed Entities. This contribution was made in exchange for aggregate consideration of:

- $3.5 billion in cash, less certain expenses incurred by us and other post-closing adjustments, relating to our acquisition of the Contributed Entities. This cash consideration was financed through the private issuance of $3.5 billion of senior unsecured notes with net proceeds of $3.466 billion.

- 203 million Class C units, which received a prorated initial distribution and were then converted to regular common units on May 10, 2010.

- An increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest.

The transactions described in the preceding paragraph are referred to as the Dropdown.

WMZ Merger

On May 24, 2010, we entered into a merger agreement with WMZ (Merger Agreement) providing for the merger of WMZ into us (the Merger). On August 31, 2010, the WMZ unitholders approved the proposed merger between the two master limited partnerships and the merger has been completed. All of WMZ s common units not held by its general partner were exchanged at a ratio of 0.7584 of our units for each WMZ unit. We now own a 100 percent interest in Northwest Pipeline GP (Northwest Pipeline), and Williams holds an approximate 77 percent interest in us, comprised of an approximate 75 percent limited partner interest and all of our 2 percent general partner interest.

Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion senior unsecured revolving three-year credit facility (Credit Facility) with Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline, as co-borrowers with borrowing sublimits of $400 million each, and Citibank, N.A., as administrative agent, and other lenders named therein. The Credit Facility replaced our previous $450 million senior unsecured credit agreement. At the closing of the Dropdown, we borrowed $250 million under the Credit Facility to repay the term loan outstanding under our previously existing credit facility. As of September 30, 2010, no loans are outstanding under the Credit Facility.

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Management s Discussion and Analysis (Continued)

Overland Pass Pipeline

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, and funded primarily with proceeds from our credit facility. (See Results of Operations Segments, Midstream Gas & Liquids.) Additionally, during September 2010, we completed an equity offering resulting in net proceeds of $380 million, which was used to reduce the borrowing on the credit facility. (See Note 5 of Notes to Consolidated Financial Statements.)

Midstream Piceance Acquisition

On October 26, 2010 we agreed to acquire certain gathering and processing assets in Colorado s Piceance Basin from our general partner, Williams, for $782 million (See Results of Operations Segments, Midstream Gas & Liquids.) We expect the transaction to be completed during the fourth quarter of 2010. The agreement includes consideration of $702 million in cash, which we expect to fund using our credit facility and/or debt, approximately 1.8 million common units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest.

Overview

We manage our business and analyze our results of operations on a segment basis. Our operations are divided into two business segments: Gas Pipeline and Midstream.

Gas Pipeline includes Transco and Northwest Pipeline, which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 trillion British thermal units (TBtu) of natural gas and peak-day delivery capacity of approximately 12 million dekatherms (MMdt) of natural gas. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 MMdt per day of natural gas.

Midstream includes natural gas gathering, processing and treating facilities, and crude oil gathering and transportation facilities with primary service areas concentrated in major producing basins in Colorado, New Mexico, Wyoming, the Gulf of Mexico, and Pennsylvania.

Company Outlook

We believe we are well positioned to continue to execute on our 2010 business plan and to 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. However, energy commodity price indicators continue to reflect an expectation of growth and increasing demand. Given the potential volatility of these measures, it is reasonably possible that the economy could worsen and/or energy commodity prices could further decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of long-lived assets.

As a result of the Dropdown, we believe we are better positioned to drive additional growth and pursue value-adding growth strategies. Additionally, the Dropdown enhances our access to capital markets.

We continue to 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 and interstate natural gas pipeline systems;

Retaining the flexibility to adjust our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

Management s Discussion and Analysis (Continued)

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

Lower than anticipated commodity prices;

Lower than expected levels of cash flow from operations;

Availability of capital;

Counterparty credit and performance risk;

Decreased volumes from third parties served by our midstream business;

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 ample liquidity from cash and cash equivalents and unused revolving credit facility capacity.

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, 50 percent of our energy derivative assets and 25 percent of our 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 our 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 significantly less than $1 million on both our net derivative assets and 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.

Our entire derivatives portfolio expires by December 31, 2010. 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 primarily of natural gas liquids swaps and forward contracts used to manage the price risk of future natural gas liquid sales. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

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Our financial swap contracts are with Williams Gas Marketing, Inc., and the derivative contracts not designated as cash flow hedging instruments are primarily physical commodity sale contracts. These agreements do not contain any provisions that require us to post collateral related to net liability positions.

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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	$ 1,291	$ 1,181	+ 110	+9%	$ 4,116	$ 3,219	+ 897	+28%
Costs and expenses:								
Costs and operating expenses	908	793	- 115	-15%	2,909	2,174	- 735	-34%
Selling, general and administrative expenses	67	72	+ 5	+7%	194	213	+ 19	+9%
Other income net	(3)	(1)	+ 2	+200%	(13)	(1)	+ 12	NM
General corporate expenses	29	26	-3	-12%	91	77	-14	-18%
Total costs and expenses	1,001	890			3,181	2,463		
Operating income	290	291			935	756		
Equity earnings	24	30	-6	-20%	77	51	+ 26	+51%
Interest accrued net	(96)	(50)	-46	-92%	(260)	(151)	- 109	-72%
Interest income		5	-5	-100%	3	16	-13	-81%
Other income net	9	4	+ 5	+125%	10	9	+ 1	+11%
Income before income taxes	227	280			765	681		
Provision for income taxes	1	1		-0%	1	4	+ 3	+75%
Net Income	226	279			764	677		
Less: Net income attributable to noncontrolling interests	5	7	+ 2	+29%	16	20	+ 4	+20%
Net income attributable to controlling interests	$ 221	$ 272			$ 748	$ 657		

*

+ = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to 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 natural gas liquids (NGL) and crude oil marketing revenues and higher NGL production revenues at Midstream, reflecting higher average NGL and crude prices, and higher revenues from transportation imbalance settlements in 2010 compared to 2009 in addition to increased natural gas transportation revenue related to expansion projects put into service at Gas Pipeline. These increases were partially offset by lower NGL equity sales volumes at Midstream.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and increased NGL production costs at Midstream, reflecting higher average NGL, crude, and natural gas prices, and an increase in costs associated with higher transportation imbalance settlements in 2010 compared to 2009 at Gas Pipeline.

Interest accrued net increased due to the $3.5 billion of senior notes that were issued in February 2010 in conjunction with the Dropdown. See Note 4 of Notes to Consolidated Financial Statements for a discussion of the debt issuance.

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

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Management s Discussion and Analysis (Continued)

The increase in *revenues* is primarily due to higher NGL and crude oil marketing revenues and higher NGL production revenues at Midstream, reflecting higher average NGL and crude prices, partially offset by lower other service revenues at Gas Pipeline and lower revenues from transportation imbalance settlements in 2010 compared to 2009.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and NGL production costs at Midstream, reflecting higher average NGL, crude, and natural gas prices, partially offset by a decrease in costs associated with lower transportation imbalance settlements in 2010 compared to 2009 at Gas Pipeline.

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

Other income net within *operating income* increased primarily due to a $14 million increase in involuntary conversion gains at Midstream due to insurance recoveries in excess of the carrying value of assets.

General corporate expenses in 2010 includes $12 million of outside services incurred related to the Dropdown.

The increase in *operating income* generally reflects an improved energy commodity price environment in 2010 compared to 2009.

Equity earnings increased primarily due to a $13 million increase from Discovery Producer Services LLC (Discovery) and an $8 million increase from Aux Sable Liquid Products LP (Aux Sable) at Midstream.

Interest accrued net increased due to the $3.5 billion of senior notes that were issued in February 2010 in conjunction with the Dropdown. See Note 4 of Notes to Consolidated Financial Statements for a discussion of the debt issuance.

Interest income decreased due primarily to lower interest rates received on advances to affiliates in 2010 compared to 2009.

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Gas Pipeline

Overview of Nine Months Ended September 30, 2010

Gas Pipeline s strategy to create value focuses on maximizing the utilization of our pipeline capacity by providing high quality, low cost transportation of natural gas to large and growing markets.

Gas Pipeline s interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission (FERC) and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, expansion or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC s ratemaking process. Changes in commodity prices and volumes transported have little near-term impact on revenues because the majority of cost of service is recovered through firm capacity reservation charges in transportation rates.

Mobile Bay South expansion project

In May 2009, we received approval from the FERC to construct a compression facility in Alabama allowing natural gas pipeline transportation service to various southbound delivery points. The cost of the project is estimated to be $32 million. The project was placed into service in May 2010 and increased capacity by 254 thousand dekatherms per day (Mdt/d).

Gas Pipeline master limited partnership

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

Outlook for the Remainder of 2010

Expansion Projects

85 North

In September 2009, we received approval from the FERC to construct 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 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.

Mobile Bay South II

In July 2010, we received approval from the FERC to construct additional compression facilities and modifications to existing facilities in Alabama allowing transportation service to various southbound delivery points. 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.

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch 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.

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	$ 409	$ 380	$ 1,196	$ 1,202
Segment profit	$ 161	$ 148	$ 478	$ 475

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

Segment revenues increased primarily due to $18 million higher transportation imbalance settlements (offset in *costs and operating expenses*) and $8 million higher transportation revenue primarily due to expansion projects placed into service in 2009 and 2010 by Transco.

Costs and operating expenses increased $19 million, or 9 percent, primarily due to $18 million higher transportation imbalance settlements (offset in *segment revenues*).

Selling, general and administrative expenses decreased $4 million, or 10 percent, primarily due to lower employee-related expenses, including pension and other postretirement benefits.

Other income net reflects increased expenses of $3 million associated with the over collection of certain employee-related expenses (offset in *segment revenues)* that will be returned to our customers and lower project development costs of $2 million.

Segment profit increased primarily due to increased transportation revenues associated with expansion projects placed into service and the other previously described changes.

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

Segment revenues decreased primarily due to an $18 million decrease in other service revenues associated with reduced customer usage of our temporary natural gas loan and storage services and $14 million lower transportation imbalance settlements (offset in *costs and operating expenses*). These decreases are partially offset by a $13 million increase in transportation revenues primarily due to expansion projects placed into service in 2009 and 2010 by Transco and a $9 million sale of base gas from an abandoned storage field (offset in *costs and operating expenses*).

Costs and operating expenses increased $3 million, reflecting a $9 million increase associated with the cost of selling base gas from an abandoned storage field (offset in *segment revenues*) and higher depreciation expense of $5 million. Offsetting these increases is reduced transportation imbalance settlements of $14 million (offset in *segment revenues*).

Selling, general and administrative expenses decreased $13 million, or 10 percent, primarily due to lower employee-related expenses, including pension and other postretirement benefits.

Other income net reflects an $8 million gain on the sale of base gas from an abandoned storage field offset by increased expense of $8 million related to the over collection of certain employee-related expenses (offset in *segment revenues*) that will be returned to our customers.

Segment profit increased primarily due to a reduction in *selling, general and administrative expenses* and the other previously described changes.

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Management s Discussion and Analysis (Continued)

Midstream Gas & Liquids

Overview of Nine Months Ended September 30, 2010

Midstream s ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers and utilizing our low cost-of-capital to invest in growing markets, including the deepwater Gulf of Mexico, the Marcellus Shale, and the western United States.

Significant events during 2010 include the following:

Piceance Acquisition

On October 26, 2010 we agreed to acquire certain gathering and processing assets in Colorado s Piceance Basin from our general partner, Williams, for $782 million. The assets include the Parachute plant complex and three other treating facilities with a combined processing capacity of 1.2 billion cubic feet per day (Bcf/d). The facilities are connected to a gathering system with approximately 150 miles of pipeline and more than 3,300 wells connected. Concurrent with the acquisition, we will execute a fee-based gas gathering agreement with Williams Exploration and Production, which will be the primary customer for these assets.

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 region due to disruptions in third-party production unrelated to the drilling moratorium, an isolated sub-sea mechanical issue that reduced other Gulf region gas production flow, 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. 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.

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 in OPPL 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

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Management s Discussion and Analysis (Continued)

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.

Management s Discussion and Analysis (Continued)

Outlook for 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. The following table presents our energy commodity derivatives as of October 21, 2010.

	Period	Volumes Hedged		Weighted Average Hedge Price (per gallon)
Designated as hedging instruments:				
NGL sales ethane (million gallons)	October December 2010	23.9	$	0.53
NGL sales propane (million gallons)	October December 2010	30.4	$	1.17
NGL sales isobutane (million gallons)	October December 2010	6.6	$	1.55
NGL sales normal butane (million gallons)	October December 2010	9.6	$	1.50
NGL sales natural gasoline (million gallons)	October December 2010	12.5	$	1.84
				(per MMbtu)
Natural gas purchases (Tbtu)	October December 2010	7.3	$	4.38

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 our Gulf Coast businesses 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 Coast areas due to natural declines, we expect 2010 fee revenues, NGL volumes, depreciation expense and operating expenses in our Gulf Coast businesses to be moderately unfavorable to 2009.

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Management s Discussion and Analysis (Continued)

Expansion Projects

Ongoing major expansion projects include:

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.

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.

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.

Period-Over-Period Operating Results

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
	(Millions)		**(Millions)**	
Segment revenues	$ 883	$ 802	$ 2,921	$ 2,023
Segment profit	$ 182	$ 199	$ 625	$ 409

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.

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.

Segment costs and expenses increased $92 million, or 15 percent, including:

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.

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.

Management s Discussion and Analysis (Continued)

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 Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses* and $6 million lower equity earnings. A more detailed analysis of the *segment profit* of certain Midstream operations is presented as follows.

The decrease in Midstream s *segment profit* includes:

A $6 million decrease in NGL production margins reflecting:

An $11 million decrease in the Gulf Coast businesses NGL margins reflecting lower equity volumes sold and a 37 percent increase in average natural gas prices, partially offset by a 32 percent increase in average NGL prices. NGL equity volumes sold were 45 percent lower primarily due to temporarily lower gas deliveries due to disruptions in third-party production unrelated to the drilling moratorium, an isolated sub-sea mechanical issue that reduced the Boomvang gas production flow and natural field declines.

A $5 million increase in the onshore businesses NGL margins reflecting a 21 percent increase in average NGL prices, partially offset by an increase in production costs reflecting a 44 percent increase in average natural gas prices. NGL equity volumes were slightly lower due primarily to the impact of a force majeure shut-down of a third-party fractionator which limited plant production delivering into Overland Pass Pipeline and maintenance issues at our Echo Springs plant, partially offset by full production at Willow Creek in 2010 compared to start-up in 2009.

A $6 million decrease in equity earnings related to a $5 million decrease from Discovery primarily due to lower system gains and lower NGL margins primarily due to lower volumes related to a change in the type of processing agreement from keep-whole to percent-of-liquids, and a $1 million decrease from Aux Sable, partially offset by a $1 million increase from our new investment in OPPL.

A $5 million decrease in fee revenues as previously discussed.

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 $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.

Segment costs and expenses increased $706 million, or 43 percent, including:

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.

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Management s Discussion and Analysis (Continued)

A $14 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 and our Ignacio plant, which was damaged by a fire in 2007.

The increase in Midstream s *segment profit* reflects the previously described changes in *segment revenues* and *segment costs and expenses* and higher equity earnings. A more detailed analysis of the *segment profit* of certain Midstream operations is presented as follows.

The increase in Midstream s *segment profit* includes:

A $192 million increase in NGL production margins reflecting:

A $163 million increase in the onshore businesses NGL margins reflecting a 58 percent increase in average NGL prices, partially offset by an increase in production costs reflecting a 49 percent increase in average natural gas prices. NGL equity volumes were slightly higher due primarily to new production at Willow Creek, partially offset by decreasing inventory in 2009.

A $29 million increase in the Gulf Coast businesses NGL margins reflecting a $38 million increase related to commodity price changes including a 49 percent increase in average NGL prices, partially offset by a 33 percent increase in average natural gas prices. NGL equity volumes sold were 10 percent lower driven by a 17 percent decrease in non-ethane volumes sold. Unfavorable impacts include temporarily lower gas deliveries due to disruptions in third-party production unrelated to the drilling moratorium, natural field declines and an isolated sub-sea mechanical issue that reduced the Boomvang gas production flow, partially offset by low recoveries, primarily of ethane, in the first quarter of 2009 driven by unfavorable NGL economics.

A $23 million increase in equity earnings, primarily due to a $13 million increase from Discovery due primarily to higher processing margins and, new volumes from the Tahiti pipeline lateral expansion completed in 2009, partially offset by lower system gains. In addition, equity earnings from Aux Sable are $8 million higher primarily due to higher processing margins.

A $10 million increase in fee revenues as previously discussed.

A $14 million favorable change related to involuntary conversion gains as previously discussed.

A $22 million decrease in margins related to the marketing of NGLs and crude primarily due to lower favorable changes in pricing while product was in transit in 2010 as compared to 2009.

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Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

For 2010, we expect operating results and cash flows to be higher than 2009 levels due to the combination of expected higher energy commodity prices and the start-up of certain expansion capital projects. However, energy commodity prices are volatile and difficult to predict. Although our cash flows are impacted by fluctuations in energy commodity prices, that impact is somewhat mitigated by certain of our cash flow streams that are not directly impacted by commodity price movements, as follows:

- Firm demand and capacity reservation transportation revenues under long-term contracts at Gas Pipeline;
- Fee-based revenues from certain gathering and processing services at Midstream;
- Hedged NGL sales and natural gas purchases for a portion of activities at Midstream.

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, unitholder distributions and debt service payments while maintaining a sufficient level of liquidity. In particular, we note the following for 2010:

- We increased our per-unit quarterly distribution from $0.6725 to $0.6875 beginning with the distribution with respect to the third quarter of 2010.
- We expect to fund capital and investment expenditures, debt service payments, distributions to unitholders and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, cash proceeds from common unit and/or long-term debt issuances and utilization of our revolving credit facility as needed. Based on a range of market assumptions, we currently estimate our cash flow from operations will be between $1.550 billion and $1.750 billion in 2010.

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 liquidity include:

- Cash and cash equivalents on hand;
- Cash generated from operations, including cash distributions from our equity-method investees;
- Cash proceeds from offerings of our common units and/or long-term debt;
- Capital contributions from Williams pursuant to the omnibus agreement;
- Use of our credit facility, as needed and available.

We anticipate our more significant uses of cash to be:

- Maintenance and expansion capital expenditures;
- Contributions to our equity-method investees to fund their expansion capital expenditures;
- Interest on our long-term debt;
- Quarterly distributions to our unitholders and/or general partner.

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Management s Discussion and Analysis (Continued)

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 expected 2010 levels;
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate policy limit is $75 million in the event of a material loss.

Available Liquidity		**September 30, 2010 (Millions)**
Cash and cash equivalents	$	92
Available capacity under our $1.75 billion three-year senior unsecured credit facility (expires February 17, 2013) (1)		1,750
	$	1,842

(1) The full amount of the credit facility is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may, under certain conditions, be increased by up to an additional $250 million. Transco and Northwest Pipeline are each able to borrow up to $400 million under the credit facility to the extent not otherwise utilized by other co-borrowers (see Note 4 of Notes to Consolidated

Financial
Statements).

Our available liquidity may be reduced during the fourth quarter related to our Midstream Piceance acquisition and/or other working capital borrowings under our credit facility. (See Results of Operations Segments, Midstream Gas & Liquids.)

Shelf Registration

On October 28, 2009, we filed a shelf registration statement as a well-known seasoned issuer that allows us to issue an unlimited amount of registered debt and limited partnership unit securities.

Distributions from Equity Method Investees

Our equity method investees organizational documents require distribution of their available cash to their members on a quarterly basis. In each case, available cash is reduced, in part, by reserves appropriate for operating their respective businesses. Our more significant equity method investees include: Aux Sable, Discovery, Gulfstream, Laurel Mountain, and OPPL.

Omnibus Agreement with Williams

In connection with the Dropdown, we entered into an omnibus agreement with Williams. Pursuant to this omnibus agreement, Williams is obligated to indemnify us from and against or reimburse us for (i) amounts incurred by us or our subsidiaries for repair or abandonment costs for damages to certain facilities caused by Hurricane Ike, up to a maximum of $10 million, (ii) maintenance capital expenditure amounts incurred by us or our subsidiaries in respect of certain U.S. Department of Transportation projects, up to a maximum aggregate amount of $50 million, and (iii) an amount based on the amortization over time of deferred revenue amounts that relate to cash payments received prior to the closing of the Dropdown for services to be rendered by us in the future at the Devils Tower floating production platform located in Mississippi Canyon Block 773. In addition, we will be obligated to pay to Williams the net proceeds of certain sales of natural gas recovered from the Hester storage field pursuant to the FERC order dated March 7, 2008, approving a settlement agreement in Docket No. RP06-569.

Management s Discussion and Analysis (Continued)

Equity Offering

On September 28, 2010, we completed an equity issuance of 9,250,000 common units representing limited partner interests in us at a price of $42.40 per unit. The net proceeds of approximately $380 million were used to repay borrowings. (See Note 5 of Notes to Consolidated Financial Statements.)

On October 8, 2010, we sold an additional 1,387,500 common units to the underwriters upon the underwriters exercise of their option to purchase additional common units pursuant to our common unit offering in September 2010. The net proceeds of $57 million were used for general corporate purposes. (See Note 5 of Notes to Consolidated Financial Statements.)

Credit Ratings

The table below presents our current credit ratings and outlook on our senior unsecured long-term debt.

Rating Agency	Date of Last Change	Outlook	Senior Unsecured Debt Rating
Standard & Poor s	January 12, 2010	Positive	BBB-
Moody s Investor Service	February 17, 2010	Stable	Baa3
Fitch Ratings	February 2, 2010	Stable	BBB-

With respect to Standard and Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard and 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 and Poor s may modify its ratings with a + or a - sign to show the obligor s relative standing within a major rating category.

With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1 , 2 , and 3 modifiers show the relative standing within a major category. A 1 indicates that an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 indicates a ranking at the lower end of the category.

With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. Fitch may add a + or a - sign to show the obligor s relative standing within a major rating category.

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 would require us to post up to $60 million in additional collateral with third parties.

Capital Expenditures

Each of our businesses is capital-intensive, requiring investment to upgrade or enhance existing operations and comply with safety and environmental regulations. The capital requirements of these businesses consist primarily of:

Maintenance capital expenditures, which are generally not discretionary, include (1) capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives, (2) expenditures which are mandatory and/or essential to comply with laws and regulations and maintain the reliability of our operations, and (3) certain well connection expenditures.

Management s Discussion and Analysis (Continued)

Expansion capital expenditures, which are generally more discretionary than maintenance capital expenditures, include (1) expenditures to acquire additional assets to grow our business, to expand and upgrade plant or pipeline capacity and to construct new plants, pipelines and storage facilities and (2) well connection expenditures which are not classified as maintenance expenditures.

The following table provides summary information related to our actual and expected capital expenditures for 2010. These amounts reflect total increases to property, plant, and equipment including accrued amounts:

	Maintenance		Expansion		Total	
Segment	2010 Estimate	Nine Months Ended September 30, 2010	2010 Estimate	Nine Months Ended September 30, 2010	2010 Estimate	Nine Months Ended September 30, 2010
			(Millions)			
Gas Pipeline	$210-230	$166	$ 275-325	$143	$ 485-555	$309
Midstream	90-100	31	1,585-1,675	162	1,675-1,775	193
Total	$300-330	$197	$1,860-2,000	$305	$2,160-2,330	$502

See Results of Operations Segments, Gas Pipeline and Midstream Gas & Liquids for discussions describing the general nature of these expenditures.

Cash Distributions to Unitholders

We have paid quarterly distributions to unitholders and our general partner after every quarter since our initial public offering on August 23, 2005. However, Williams waived its incentive distribution rights related to the 2009 distribution periods. We have increased our quarterly distribution from $0.6725 to $0.6875 per unit. The distribution with respect to the third quarter of 2010 will be approximately $250 million, which will be paid on November 12, 2010, to the general and limited partners of record at the close of business on November 5, 2010.

Sources (Uses) of Cash

	Nine months ended September 30, 2010	Nine months ended September 30, 2009
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 1,353	$ 1,041
Financing activities	3,011	(300)
Investing activities	(4,425)	(764)
Decrease in cash and cash equivalents	$ (61)	$ (23)

Operating Activities

Net cash provided by operating activities for the nine months ended September 30, 2010 increased from the same period in 2009 primarily due to higher operating income and changes in working capital.

Financing Activities

Significant transactions include:

$430 million received in revolver borrowings from our $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 our September 2010 equity offering used to reduce revolver borrowings mentioned above;

$3.5 billion of net proceeds from the issuance of senior unsecured notes in 2010;

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Management s Discussion and Analysis (Continued)

- $250 million received from revolver borrowings on our $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 4 of Notes to Consolidated Financial Statements);
- $410 million and $110 million in 2010 and 2009, respectively, related to cash distributions paid to unit holders.

Investing Activities

Significant transactions include:

- $424 million cash payment for our September 2010 acquisition of an increased interest in OPPL (see Results of Operations Segment, Midstream Gas & Liquids);
- $3.4 billion related to the cash consideration paid to Williams in the Dropdown transaction in 2010;
- Capital expenditures in 2010 and 2009 totaled $570 million and $624 million, respectively;
- $100 million cash payment in 2009 for our 51 percent ownership interest in the joint venture Laurel Mountain;
- $73 million of cash received in 2009 as a distribution from Gulfstream following its debt offering.

Off-Balance Sheet Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at September 30, 2010.

Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

The Dropdown and related debt issuance had a significant impact on our debt portfolio but did not materially change our interest rate risk exposure. (See Note 4 of Notes to Consolidated Financial Statements.)

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas liquids (NGL) and natural gas, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets and our long-term energy-related contracts. We manage a portion of the risks associated with these market fluctuations using various derivative 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. (See Note 7 of Notes to Consolidated Financial Statements.)

We measure the risk in our portfolio using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolio. 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 portfolio. 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 portfolio will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints. Our derivative contracts are contracts held for nontrading purposes and hedge a portion of our commodity price risk exposure from NGL sales and natural gas purchases.

The value at risk was $0.9 million at September 30, 2010 and $0.1 million at December 31, 2009.

Substantially all of the derivative contracts included in our value-at-risk calculation are accounted for as cash flow hedges. Any change in the fair value 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 general partner s 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 Williams Partners L.P. 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 general partner s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our management concluded that these Disclosure Controls are effective at a reasonable assurance level.

Third-Quarter 2010 Changes in Internal Controls

In the third quarter, we completed the first phase of implementing a new measurement system utilized in certain of our gathering and processing locations in our Midstream segment. 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 8 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:

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Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities and could exceed current expectations.

The risk of substantial environmental costs and liabilities is inherent in natural gas gathering, transportation, storage, processing and treating, and in the fractionation and storage of NGLs, and we may incur substantial environmental costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local environmental laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- CAA and analogous state laws, which impose obligations related to air emissions;
- CWA, and analogous state laws, which regulate discharge of wastewaters from our facilities to state and federal waters;
- CERCLA, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal; and
- RCRA, and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from 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.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to our handling of the products we gather, transport, process, fractionate and store, air emissions related to our operations, historical industry operations, waste disposal practices, and the prior use of flow meters containing mercury. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA, and analogous state laws, 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 and facilities where our wastes are taken for reclamation or disposal, may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites we operate are located near current or former third-party hydrocarbon storage and processing operations, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

Our business may be adversely affected by increased costs due to stricter pollution control requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. 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 business, financial condition, results of operations and cash flows.

In addition, recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), may be contributing to warming of the earth s atmosphere, and various governmental bodies have considered legislative and regulatory responses in this area.

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Legislative and regulatory responses related to 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, regional and/or federal requirements to reduce or mitigate GHG emissions.

Several bills have been introduced in the United States Congress that would compel GHG emission reductions. On June 26, 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 could ultimately lead to the direct regulation of GHG emissions in our industry under the CAA. 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 and our ability to make cash distributions to unitholders. To the extent financial markets view climate change and GHG emissions 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, and any new capital costs incurred to comply with such changes may not be recoverable under our regulatory rate structure or our customer contracts. In addition, new environmental laws and regulations might adversely affect our products and activities, including processing, fractionation, storage and transportation, as well as waste management and air emissions. For instance, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

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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 or other partnership purposes. 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 No.	Description
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, and 6 (filed on February 25, 2010 as Exhibit 3.3 to Williams Partners L.P. s annual report on Form 10-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
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.

WILLIAMS PARTNERS L.P.
(Registrant)
By: Williams Partners GP LLC, its general partner

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

October 28, 2010

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