Williams Partners L.P.
Form 10-Q
May 05, 2011

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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 March 31, 2011

OR

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

For the transition period from __________ to __________

Commission file number 1-32599

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, including area code: (918) 573-2000

NO CHANGE

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 289,844,575 common units outstanding as of May 4, 2011.

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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 maintain current levels of cash distributions or 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 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;
- Additional risks described in our filings with the Securities and Exchange Commission (SEC).

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

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

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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

	Three months ended March 31, 2011	2010
	(Millions, except per-unit amounts)	
Revenues:		
Gas Pipeline	$ 416	$ 407
Midstream Gas & Liquids	1,163	1,083
Total revenues	1,579	1,490
Segment costs and expenses:		
Costs and operating expenses	1,105	1,033
Selling, general and administrative expenses	73	62
Other income net	(11)	(3)
Segment costs and expenses	1,167	1,092
General corporate expenses	30	35
Operating income:		
Gas Pipeline	166	160
Midstream Gas & Liquids	246	238
General corporate expenses	(30)	(35)
Total operating income	382	363
Equity earnings	25	26
Interest accrued	(108)	(81)
Interest capitalized	2	12
Interest income	1	3
Other income (expense) net	5	(1)
Net income	307	322
Less: Net income attributable to noncontrolling interests		6
Net income attributable to controlling interests	$ 307	$ 316
Allocation of net income for calculation of earnings per common unit:		
Net income attributable to controlling interests	$ 307	$ 316
Allocation of net income to general partner and Class C units	71	284
Allocation of net income to common units	$ 236	$ 32
Basic and diluted net income per common unit	$ 0.81	$ 0.61
Weighted average number of common units outstanding	289,844,575	52,777,452
Cash distributions per common unit	$ 0.7175	$ 0.6575

See accompanying notes.

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

	March 31, 2011	December 31, 2010
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 232	$ 187
Accounts receivable:		
Trade	391	404
Affiliate	10	8
Inventories	173	195
Regulatory assets	48	51
Other current assets	45	53
Total current assets	899	898
Investments	1,077	1,045
Gross property, plant and equipment	16,849	16,707
Less accumulated depreciation	(5,842)	(5,706)
Property, plant and equipment net	11,007	11,001
Regulatory assets, deferred charges and other	454	460
Total assets	$ 13,437	$ 13,404
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 373	$ 322
Affiliate	92	154
Accrued interest	105	105
Other accrued liabilities	187	174
Long-term debt due within one year	458	458
Total current liabilities	1,215	1,213
Long-term debt	6,366	6,365
Asset retirement obligations	455	460
Regulatory liabilities, deferred income and other	281	290
Contingent liabilities and commitments (Note 7)		
Equity:		
Common units (289,844,575 units outstanding at March 31, 2011 and December 31, 2010)	6,600	6,564
General partner	(1,475)	(1,485)
Accumulated other comprehensive income (loss)	(5)	(3)

Total equity	5,120	5,076
Total liabilities and equity	$ 13,437	$ 13,404

See accompanying notes.

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

	Common Units	General Partner	Accumulated Other Comprehensive Loss	Total Equity
		(Millions)		
Balance January 1, 2011	$ 6,564	$ (1,485)	$ (3)	$ 5,076
Comprehensive income:				
Net income	240	67		307
Other comprehensive loss:				
Net unrealized change in cash flow hedges			(2)	(2)
Total other comprehensive loss				(2)
Total comprehensive income				305
Cash distributions	(204)	(64)		(268)
Other		7		7
Balance March 31, 2011	$ 6,600	$ (1,475)	$ (5)	$ 5,120

See accompanying notes.

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

	Three months ended March 31, 2011	2010
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 307	$ 322
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	150	140
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	13	9
Inventories	22	(20)
Other assets and deferred charges	13	24
Accounts payable	65	17
Accrued liabilities	12	17
Affiliates net	(64)	74
Other, including changes in noncurrent assets and liabilities	(7)	13
Net cash provided by operating activities	511	596
FINANCING ACTIVITIES:		
Proceeds from long-term debt		3,749
Payments of long-term debt		(407)
Payment of debt issuance costs		(60)
Dividends paid to noncontrolling interests		(6)
Distributions to limited partners and general partner	(268)	(34)
Distributions to The Williams Companies, Inc. net		(305)
Other net	(1)	(17)
Net cash provided (used) by financing activities	(269)	2,920
INVESTING ACTIVITIES:		
Purchase of Contributed Entities		(3,420)
Property, plant and equipment:		
Capital expenditures	(156)	(120)
Net proceeds from dispositions	(8)	6
Purchase of investments	(36)	(9)
Other net	3	2
Net cash used by investing activities	(197)	(3,541)
Increase (decrease) in cash and cash equivalents	45	(25)
Cash and cash equivalents at beginning of period	187	153

Cash and cash equivalents at end of period	$	232	$	128

See accompanying notes.

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. As of March 31, 2011, Williams owns an approximate 73 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, 2010 in our Annual report on Form 10-K. 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 March 31, 2011, results of operations for the three months ended March 31, 2011 and 2010, changes in equity for the three months ended March 31, 2011, and cash flows for the three months ended March 31, 2011 and 2010.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Basis of Presentation

During fourth-quarter 2010, we closed the acquisition of a business represented by certain gathering and processing assets in Colorado s Piceance Basin from a subsidiary of Williams (the Piceance Acquisition). As the acquired assets were purchased from a subsidiary of Williams, the transaction was accounted for as a combination of entities under common control whereby the assets and liabilities acquired are combined with ours at their historical amounts. The acquired assets are reported in our Midstream Gas & Liquids (Midstream) segment, which includes a recast of the statement of income for the prior period. The effect of recasting our financial statements to account for this transaction increased net income by $9 million for the three months ended March 31, 2010. This acquisition does not impact historical earnings per unit as pre-acquisition earnings 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 is comprised primarily of the following interstate natural gas pipeline assets:

- Transcontinental Gas Pipe Line Company, LLC (Transco), an interstate natural gas pipeline extending from the Gulf of Mexico region to the northeastern United States;
- Northwest Pipeline GP (Northwest Pipeline), an interstate natural gas pipeline extending from the San Juan basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington;
- A 24.5 percent equity interest in Gulfstream Natural Gas System L.L.C. (Gulfstream), an interstate natural gas pipeline extending from the Mobile Bay area in Alabama to markets in Florida.

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Notes (Continued)

Midstream is comprised primarily of the following natural gas gathering, processing and treating facilities, oil gathering and transportation facilities and natural gas liquid (NGL) transportation, fractionation and storage facilities and investments:

- Two gathering systems and the Echo Springs and Opal processing plants serving the Wamsutter and southwest areas of Wyoming;
- A gathering system, the Ignacio, Kutz and Lybrook processing plants and the Milagro and Esperanza natural gas treating plants, all serving the San Juan basin in New Mexico and Colorado;
- A gathering system, natural gas liquids pipeline and the Willow Creek and Parachute processing plants in Colorado;
- An equity interest in Laurel Mountain Midstream, LLC, serving the Marcellus shale region of western Pennsylvania;
- Gathering pipelines and compressor stations in the Appalachian basin of Pennsylvania;
- Onshore and offshore natural gas and oil gathering pipelines in the Gulf Coast region;
- The Mobile Bay and Markham processing plants in the Gulf Coast region;
- The Canyon Station and Devils Tower offshore production platforms in the Gulf of Mexico;
- Four Gulf of Mexico deepwater crude oil pipelines;
- NGL storage facilities in the Conway, Kansas area;
- Interests in two NGL fractionation facilities: one near Conway, Kansas and the other in Baton Rouge, Louisiana;
- An equity interest in Discovery Producer Services LLC, whose assets include a processing plant and a fractionation plant in Louisiana, and an offshore natural gas gathering and transportation system in the Gulf of Mexico;
- An equity interest in Aux Sable Liquid Products LP, whose assets include a processing plant and a fractionator in Illinois;
- An equity interest in Overland Pass Pipeline Company LLC, whose assets include a natural gas liquids pipeline stretching from Wyoming through Colorado and into Kansas.

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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 months ended March 31, 2011 and 2010, is as follows:

	Three months ended March 31,	
	2011	**2010**
	(Millions)	
Allocation of net income to general partner:		
Net income	$ 307	$ 322
Net income applicable to pre-partnership operations allocated to general partner		(172)
Net income applicable to noncontrolling interests		(6)
Net reimbursable costs charged directly to general partner	(2)	(2)
Income subject to 2% allocation of general partner interest	305	142
General partner s share of net income	2.0%	2.0%
General partner s allocated share of net income before items directly allocable to general partner interest	6	3
Incentive distributions paid to general partner*	59	
Net reimbursable costs charged directly to general partner	2	2
Pre-partnership net income allocated to general partner interest		172
Net income allocated to general partner	$ 67	$ 177
Net income	$ 307	$ 322
Net income allocated to general partner	67	177
Net income allocated to Class C limited partners		89
Net income allocated to noncontrolling interests		6
Net income allocated to common limited partners	$ 240	$ 50

* In the calculation of basic and diluted net income per common 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 *net reimbursable costs charged directly to general partner* may include the net of both income and expense items. Under the terms of omnibus agreements, we are reimbursed by our general partner for certain expense items and are required to distribute certain income items to our general partner.

Total comprehensive income for the three months ended March 31, 2011 and 2010 is $305 million and $310 million, respectively. The difference between total comprehensive income and net income for all periods is due to net unrealized changes in cash flow hedges.

Notes (Continued)

We paid or have authorized payment of the following partnership cash distributions during 2010 and 2011 (in millions, except for per unit amounts):

Payment Date	Per Unit Distribution	Common Units	Class C Units	2%	Incentive Distribution Rights	Total Cash Distribution
2/12/2010	$0.6350	$ 33	$	$1	$	$ 34
5/14/2010	$0.6575	$ 35	$87	$3	$ 30	$ 155
8/13/2010	$0.6725	$172	$	$4	$ 45	$ 221
11/12/2010	$0.6875	$192	$	$5	$ 53	$ 250
2/11/2011	$0.7025	$204	$	$5	$ 59	$ 268
5/13/2011(a)	$0.7175	$208	$	$5	$ 63	$ 276

(a) The Board of Directors of our general partner declared this cash distribution on April 21, 2011, to be paid on May 13, 2011, to unitholders of record at the close of business on May 6, 2011.

Note 3. Other Accruals

Other income net within *segment costs and expenses* in 2011 includes $10 million related to the reversal of project feasibility costs from expense to capital at Gas Pipeline, associated with an expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we belive are probable of recovery through the project rates.

Note 4. Inventories

	March 31, 2011	December 31, 2010
	(Millions)	
Natural gas liquids	$ 53	$ 61
Natural gas in underground storage	49	62
Materials, supplies, and other	71	72
	$ 173	$ 195

Note 5. Fair Value Measurements

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

	March 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Assets:								
ARO Trust investments (see Note 6)	$ 38	$	$	$ 38	$ 40	$	$	$ 40
Energy derivatives		3		3				
Total assets	$ 38	$ 3	$	$ 41	$ 40	$	$	$ 40

Liabilities:												
Energy derivatives	$		$	5	$		$	5	$	$	$	$
Total liabilities	$		$	5	$		$	5	$	$	$	$

The instruments included in our Level 1 measurements consist of a portfolio of mutual funds. (See Note 6.)

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Notes (Continued)

The instruments included in our Level 2 measurements consist primarily of over-the-counter (OTC) instruments such as natural gas and natural gas liquid (NGL) swaps. 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.

Certain instruments trade 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 because these inputs have a significant impact on the measurement of fair value. As of March 31, 2011 and December 31, 2010, we do not have any instruments classified as Level 3.

The tenure of our derivatives portfolio is relatively short with all of our derivatives expiring by December 31, 2011. 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.

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 March 31, 2011 or 2010. During the period ended March 31, 2011, certain NGL swaps that originated during the first quarter of 2011 were transferred from Level 3 to Level 2. Prior to March 31, 2011, such swaps were considered Level 3 due to a lack of observable third-party market quotes. Due to an increase in exchange-traded transactions and greater visibility from OTC trading, we transferred these instruments to Level 2.

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

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Three months ended March 31,	
	2011	**2010**
	(Millions)	
Beginning balance	$	$
Realized and unrealized gains (losses):		
Included in net income		(1)
Included in other comprehensive income (loss)	(5)	5
Settlements		
Transfers into Level 3		
Transfers out of Level 3	5	
Ending balance	$	$ 4
Unrealized gains (losses) included in net income relating to instruments still held at March 31	$	$

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

For the three months ended March 31, 2011 and 2010, there were no assets or liabilities measured at fair value on a nonrecurring basis.

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Notes (Continued)

Note 6. Financial Instruments, Derivatives, and Guarantees

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 determined using indicative period-end traded bond market prices. At both March 31, 2011 and December 31, 2010, approximately 100 percent of our long-term debt was publicly traded.

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 5 for a discussion of the valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	March 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Asset (Liability)				
Cash and cash equivalents	$ 232	$ 232	$ 187	$ 187
ARO Trust investments	$ 38	$ 38	$ 40	$ 40
Long-term debt, including current portion	$(6,824)	$(7,272)	$(6,823)	$(7,283)
Energy commodity cash flow hedges	$ (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. Those designated as cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

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Notes (Continued)

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:

Central hub risk*:* Financial derivative exposures to Henry Hub for natural gas and Mont Belvieu for NGLs;

Basis risk*:* Financial derivative exposures to the difference in value between the central hub and another specific delivery point.

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of March 31, 2011. Natural gas is presented in millions of British Thermal Units (MMBtu) and NGLs are presented in gallons.

Derivative Notional Volumes		**Unit of Measurement**	**Central Hub Risk**	**Basis Risk**
Designated as Hedging Instruments				
Midstream	Risk Management	MMBtu	8,250,000	7,562,500
Midstream	Risk Management	Gallons	(2,280,000)	
Not Designated as Hedging Instruments				
Midstream	Risk Management	Gallons	(50,000)	

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 2011.

	March 31, 2011		**December 31, 2010**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Millions)		**(Millions)**	
Designated as hedging instruments	$ 3	$ 5	$	$
Not designated as hedging instruments				
Total derivatives	$ 3	$ 5	$	$

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

	Three months ended March 31,		
	2011	**2010**	**Classification**
	(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$ (2)	$ (6)	AOCI
Net gain (loss) reclassified from accumulated other comprehensive income (loss) into income (effective portion)	$	$ (2)	Revenues or Costs and Operating Expenses
Gain (loss) recognized in income (ineffective portion)	$	$	Revenues or Costs and Operating Expenses

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Notes (Continued)

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 March 31, 2011, we have hedged portions of future cash flows associated with anticipated NGL sales and natural gas purchases through 2011. Based on recorded values at March 31, 2011, net losses to be reclassified into earnings by December 31, 2011, are $2 million. These recorded values are based on market prices of the commodities as of March 31, 2011. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized by December 31, 2011, 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 in *revenues* for both the three months ended March 31, 2011 and 2010 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

The majority of our financial swap contracts are with our affiliate, Williams Gas Marketing, Inc., and the derivative contracts not designated as cash flow hedging instruments are primarily NGL swaps. These agreements do not contain any provisions that require us to post collateral related to net liability positions.

Guarantees

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 March 31, 2011, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have a material adverse effect on our results of operations.

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Notes (Continued)

Note 7. Contingent Liabilities

Environmental Matters

Our interstate gas pipelines are involved in remediation activities related to certain facilities and locations for polychlorinated biphenyl, mercury contamination, and other hazardous substances. These activities have involved the U.S. Environmental Protection Agency (EPA), various state environmental authorities and identification as a potentially responsible party at various Superfund waste sites. At March 31, 2011, we have accrued liabilities of $12 million for these costs. We expect that these costs will be recoverable through rates.

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 violation 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. The EPA has requested additional information pertaining to these compressor stations, most recently in February 2011. In August 2010, the EPA requested, and Transco later provided, similar information for a compressor station in Maryland.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. Tentative settlement has been reached in first-quarter 2011.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At March 31, 2011, we have accrued liabilities totaling $7 million for these costs.

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

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. If the FERC were to reverse their opinion on rehearing, we believe any refunds would not be material to our results of operations.

Safety Matters

Transco and Northwest Pipeline have developed an Integrity Management Plan that we believe meets the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration final rule that was issued pursuant to the requirements of the Pipeline Safety Improvement Act of 2002. The rule requires gas pipeline operators to develop an integrity management program for transmission pipelines that could affect high consequence areas in the event of pipeline failure. The Integrity Management Program includes a baseline assessment plan along with periodic reassessments to be completed within required timeframes. In meeting the integrity regulations, they have identified high consequence areas and developed baseline assessment plans. They are on schedule to complete

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Notes (Continued)

the required assessments within required timeframes. Currently, we estimate the cost to complete the required initial assessments over the period of 2011 through 2012 and associated remediation will be primarily capital in nature and range between $80 million and $110 million for Transco and between $50 million and $60 million for Northwest Pipeline. Ongoing periodic reassessments and initial assessments of any new high consequence areas will be completed within the timeframes required by the rule. 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 our rates.

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 8. 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*.

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.

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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 (Millions)	Total
Three months ended March 31, 2011			
Segment revenues:			
External	$ 416	$ 1,163	$ 1,579
Total revenues	$ 416	$ 1,163	$ 1,579
Segment profit	$ 175	$ 262	$ 437
Less equity earnings	9	16	25
Segment operating income	$ 166	$ 246	412
General corporate expenses			(30)
Total operating income			$ 382
Three months ended March 31, 2010			
Segment revenues:			
External	$ 407	$ 1,083	$ 1,490
Total revenues	$ 407	$ 1,083	$ 1,490
Segment profit	$ 169	$ 255	$ 424
Less equity earnings	9	17	26
Segment operating income	$ 160	$ 238	398
General corporate expenses			(35)
Total operating income			$ 363

Note 9. Subsequent Event

During April 2011, we agreed to acquire from Williams an additional 24.5 percent interest in Gulfstream in exchange for aggregate consideration of $297 million of cash, 632,584 of our limited partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. We expect to fund the cash consideration for this transaction through our credit facility. Since the additional 24.5 percent interest was acquired from an entity under the common control of Williams, it will be recorded at Williams   historical book value which was approximately $185 million at March 31, 2011. The transaction is expected to close during the second quarter 2011.

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

Overview

The Williams Companies, Inc. (Williams) holds an approximate 75 percent interest in us, comprised of an approximate 73 percent limited partner interest and all of our 2 percent general partner interest.

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 & Liquids (Midstream).

Gas Pipeline includes Transcontinental Gas Pipe Line Company, LLC (Transco) and Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream Natural Gas System L.L.C. (Gulfstream), which owns an approximate 745-mile pipeline.

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.

Overview of Three Months Ended March 31, 2011

Net Income for the three months ended March 31, 2011, changed unfavorably by $15 million compared to the three months ended March 31, 2010, primarily due to higher interest expense associated with increased debt levels in conjunction with the 2010 contribution of subsidiaries from our general partner, partially offset by a $10 million reversal of project feasibility costs from expense to capital, associated with an expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates. (See Results of Operations Consolidated Overview.)

Our *net cash provided by operating activities* for the three months ended March 31, 2011, decreased $85 million compared to the three months ended March 31, 2010, primarily due to the timing of settling certain affiliate balances.

Recent Events

During April 2011, we agreed to acquire from Williams an additional 24.5 percent interest in Gulfstream in exchange for aggregate consideration of $297 million of cash, 632,584 of our limited partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. We expect to fund the cash consideration for this transaction through our credit facility. Upon completing this transaction, which we expect to close during the second quarter of 2011, we will hold a 49 percent interest in Gulfstream.

In April 2011 our Board of Directors approved a 2 percent increase to our quarterly distribution to unitholders. (See Management s Discussion and Analysis of Financial Condition and Liquidity.)

Company Outlook

We believe we are well-positioned to execute on our 2011 business plan and to capture attractive growth opportunities. We expect increases in our operating results over 2010 due primarily to continued strong per-unit NGL margins in our Midstream business in relation to five-year averages and our significant 2010 growth capital investments. We are cautiously optimistic that growth in the broader economy will continue to improve in 2011, but numerous uncertainties exist. Energy commodity price indicators continue to reflect an expectation of growth and increasing demand. Given the potential volatility of these measures, the economy could worsen and/or energy commodity margins could further decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of long-lived assets.

We believe we are positioned to drive additional organic growth and aggressively pursue value-adding growth opportunities.

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 somewhat our planned levels of capital and investment expenditures in response to changes in economic conditions or business opportunities.

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

- Lower than anticipated commodity prices and margins;
- 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.

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.

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 months ended March 31, 2011, compared to the three months ended March 31, 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31,		$ Change*	% Change*
	2011	2010		
	(Millions)			
Revenues	$ 1,579	$ 1,490	+ 89	+6%
Costs and expenses:				
Costs and operating expenses	1,105	1,033	- 72	-7%
Selling, general and administrative expenses	73	62	- 11	-18%
Other income net	(11)	(3)	+ 8	NM
General corporate expenses	30	35	+ 5	+14%
Total costs and expenses	1,197	1,127		
Operating income	382	363		
Equity earnings	25	26	- 1	-4%
Interest accrued net	(106)	(69)	- 37	-54%
Interest income	1	3	- 2	-67%
Other income (expense) net	5	(1)	+ 6	NM
Net income	307	322		
Less: Net income attributable to noncontrolling interests		6	+ 6	+100%
Net income attributable to controlling interests	$ 307	$ 316		

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

Three months ended March 31, 2011 vs. three months ended March 31, 2010

The increase in *revenues* is primarily due to higher marketing revenues at Midstream from higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes. The increase is partially offset by decreased NGL production revenues at Midstream due to lower NGL volumes, partially offset by higher average NGL per-unit sales prices.

The increase in *costs and operating expenses* is primarily due to increased marketing purchases at Midstream primarily due to higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes and increased operating costs at Midstream. The increased operating costs are primarily due to higher depreciation, an unfavorable change in system gains and losses, and higher maintenance costs. These increases are partially offset by decreased costs associated with production of NGLs reflecting lower average natural gas prices and lower NGL volumes.

The increase in *selling, general and administrative expenses* includes higher employee-related expenses at Gas Pipeline.

Other income — net within *operating income* increased primarily due to a $10 million reversal of project feasibility costs from expense to capital at Gas Pipeline, associated with an expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates.

The increase in *operating income* is primarily due to the increase in *other income — net* previously discussed.

The increase in *interest accrued net* is primarily due to the $3.5 billion of senior notes issued in February 2010 and $600 million of senior notes issued in November 2010. In addition, 2010 project completions at Midstream contributed to a decrease in interest capitalized.

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Gas Pipeline

Overview of Three Months Ended March 31, 2011

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.

Outlook for the Remainder of 2011

Recent events

During April 2011, we agreed to acquire from Williams an additional 24.5 percent interest in Gulfstream in exchange for $297 million of cash, 632,584 limited partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. We expect to fund the cash consideration for this transaction through our credit facility. The transaction is expected to close during the second quarter of 2011.

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 $227 million. Phase I was placed into service in July 2010 and increased capacity by 90 thousand dekatherms per day (Mdt/d). Phase II was placed into service in May 2011 and has increased 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 $35 million. The project was placed into service in May 2011 and has increased capacity by 380 Mdt/d.

Mid-South

In October 2010, we filed an application with the FERC to upgrade compressor facilities and expand our existing natural gas transmission system from Alabama to markets as far north as North Carolina. The cost of the project is estimated to be $217 million. The project is expected to be phased into service in September 2012 and June 2013, with an increase in capacity of 225 Mdt/d.

Mid-Atlantic Connector

In November 2010, we filed an application with the FERC to expand our existing natural gas transmission system from North Carolina to markets as far downstream as Maryland. The cost of the project is estimated to be $55 million and will increase capacity by 142 Mdt/d. We plan to place the project into service in November 2012.

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Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended March 31,			
	2011		2010	
	(Millions)			
Segment revenues	$	416	$	407
Segment profit	$	175	$	169

Three months ended March 31, 2011 vs. three months ended March 31, 2010

Segment revenues increased $9 million, or 2 percent, primarily due to higher transportation revenue associated with expansion projects placed into service in 2010.

Costs and operating expenses increased $7 million, or 3 percent, primarily due to $4 million increased operations and maintenance expense related to a natural gas storage cavern leak and $2 million higher depreciation expense resulting from additional assets placed in service in 2010.

Selling, general and administrative expenses increased $7 million, or 22 percent, primarily due to higher employee-related expenses.

Other income (expense) net improved $12 million primarily due to a $10 million reversal of project feasibility costs from expense to capital, associated with an expansion project, upon determining that the related project was probable of development. These costs will be included in the capital costs of the project, which we believe are probable of recovery through the project rates.

Segment profit increased due to the previously described changes.

Midstream Gas & Liquids

Overview of Three Months Ended March 31, 2011

Midstream s ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. We focus on consistently attracting new business by providing highly reliable service to our customers.

Significant events during 2011 include the following:

Perdido Norte

Both oil and gas production began to flow on a sustained basis during the fourth quarter of 2010 through our Perdido Norte expansion, located in the western deepwater of the Gulf of Mexico. The project includes a 200 MMcf/d expansion of our onshore Markham gas processing facility and a total of 179 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure. While production volumes are currently significantly lower than expected, producers continue to work through technical issues and we anticipate volumes to increase significantly during 2011.

Overland Pass Pipeline

We became operator of Overland Pass Pipeline Company LLC (OPPL) effective April 1, 2011. We own a 50 percent interest in OPPL which 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-Julesburg basins in Colorado, respectively. Our equity NGL volumes from our two Wyoming plants and our Willow Creek plant in Colorado are dedicated for transport on OPPL under a long-term shipping agreement. Work is under way to determine optimal expansions to serve producers in the OPPL corridor.

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Management s Discussion and Analysis (Continued)

Marcellus Shale Gathering Asset Transition and Expansion

We assumed operational activities for a gathering business in Pennsylvania s Marcellus Shale which we acquired at the end of 2010. This business includes 75 miles of gathering pipelines and two compressor stations. We expect gathered volumes to increase in 2011 under our long-term dedicated gathering agreement for the seller s production. Additionally, engineering and construction activities continue on our Springville gathering pipeline which will connect the gathering system into the Transco pipeline.

Volatile commodity prices

Average per-unit NGL margins in the first quarter of 2011 are significantly higher than the same period in 2010, benefiting from significantly lower natural gas prices driven by abundant natural gas supplies, while a strong demand for NGLs has resulted in slightly higher NGL prices.

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. Our equity volumes include NGLs where we own the rights to the value from NGLs recovered at our plants under both keep-whole processing agreements, where we have the obligation to replace the lost heating value with natural gas, and percent-of-liquids agreements whereby we receive a portion of the extracted liquids with no obligation to replace the lost heating value.

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Management s Discussion and Analysis (Continued)

Outlook for Remainder of 2011

The following factors could impact our business in 2011.

Commodity price changes

We expect our average per-unit NGL margins in 2011 to be higher than 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, difficult to predict and are often not highly correlated. 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 14 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink gas requirements for the remainder of 2011. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $171 million. The following table presents our energy commodity derivatives, as of April 29, 2011.

	Period	**Volumes Hedged**	**Weighted Average Hedge Price**
Designated as hedging instruments:			**(per gallon)**
NGL sales ethane (million gallons)	Apr - Dec 2011	26.3	$ 0.72
NGL sales propane (million gallons)	Apr - Dec 2011	47.5	$ 1.36
NGL sales isobutane (million gallons)	Apr - Dec 2011	14.7	$ 1.91
NGL sales normal butane (million gallons)	Apr - Dec 2011	15.1	$ 1.79
NGL sales natural gasoline (million gallons)	Apr - Dec 2011	31.3	$ 2.46
			(per MMbtu)
Natural gas purchases (Tbtu)	Apr - Dec 2011	11.3	$ 3.95

Gathering, processing, and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities.

We anticipate growth in our onshore businesses gas gathering and processing volumes as our infrastructure grows to support drilling activities in the Piceance and Appalachian basins. However, we anticipate no change or slight declines in basins in the Rocky Mountain and Four Corners areas due to reduced drilling activity. Due to the high proportion of fee-based processing agreements in the Piceance basin, we anticipate only a slight increase in NGL equity sales volumes.

In our Gulf Coast businesses, we expect higher gas gathering, processing and crude transportation volumes as our Perdido Norte pipelines move into a full year of operation and other in-process drilling is completed. Recent increases in permitting, subsequent to the 2010 drilling moratorium, give us reason to expect gradual increased drilling activities in the Gulf of Mexico. While we expect an overall increase in processed gas volumes in 2011, NGL equity volumes are expected to be lower as a major contract changed from keep-whole to percent-of-liquids processing.

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Management s Discussion and Analysis (Continued)

Expansion projects

We have planned growth capital and investment expenditures of $860 million to $1,090 million in 2011, of which $800 million to $1,030 million remains to be spent. Major projects include expansions to our newly acquired gathering system in the Appalachian basin as well as our Laurel Mountain Midstream, LLC (Laurel Mountain) equity investment, which combined are expected to provide 2.75 Bcf/d of gathering capacity by 2015. We also plan to pursue major expansion and growth opportunities in the Gulf of Mexico, as well as in the Piceance basin.

Our ongoing major expansion projects include:

Additional gathering assets, including compression and dehydration, in the Appalachian basin. In conjunction with a long-term agreement with a significant producer, we plan to construct and operate a 33-mile, 24-inch diameter natural gas gathering pipeline in the Marcellus Shale region which will connect our recently acquired gathering assets in Pennsylvania s Marcellus Shale into the Transco pipeline. Engineering and construction activities on the Springville pipeline and compressor station have begun and that project is expected to be completed in the latter part of 2011. Other compression and dehydration projects to increase capacity to approximately 500 to 550 MMcf/d are nearing completion and are expected to be in service by the end of the second quarter of 2011.

Capital to be invested within our Laurel Mountain equity investment, also in the Marcellus Shale region, to enable the rapid expansion of our gathering system including the initial stages of projects that are planned to provide approximately 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. The initial phase of our Shamrock compressor station went in service during the first quarter of 2011, providing 30 MMcf/d of additional capacity, with another 150 MMcf/d expected to be available by the end of the fourth quarter of 2011. This compressor station is expandable to 350 MMcf/d, and will likely be the largest central delivery point out of the Laurel Mountain system.

Additional capital to expand our gathering system infrastructure in the Piceance basin.

Period-Over-Period Operating Results

	Three months ended March 31,	
	2011	**2010**
	(Millions)	
Segment revenues	$ 1,163	$ 1,083
Segment profit	$ 262	$ 255

Three months ended March 31, 2011 vs. Three months ended March 31, 2010

The increase in *segment revenues* includes:

A $102 million increase in marketing revenues primarily due to higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes. These changes are offset by similar changes in marketing purchases.

A $12 million increase in fee revenues primarily due to higher gathering and processing fee revenue in the Piceance basin as a result of the agreement with Williams Exploration & Production executed in November 2010 and new gathering fee revenues from our recently acquired gathering assets in the Marcellus Shale. These increases are partially offset by a decline in gathering and transportation fees in the Four Corners area and in the deepwater of the eastern Gulf of Mexico due primarily to natural field declines.

A $32 million decrease in revenues associated with the production of our equity NGLs reflecting a decrease of $40 million associated with a 13 percent decrease in NGL volumes, partially offset by an increase of $8 million associated with a slight increase in average NGL per-unit sales prices.

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Management s Discussion and Analysis (Continued)

Segment costs and expenses increased $72 million, or 9 percent, including:

- A $90 million increase in marketing purchases primarily due to higher average NGL and crude prices and higher NGL volumes, partially offset by lower crude volumes. These changes are offset by similar changes in marketing revenues.

- A $22 million increase in operating costs including $8 million higher depreciation primarily due to our new Perdido Norte pipelines, a $6 million unfavorable change related to system losses in the current period compared with system gains in the same period in 2010 and $6 million higher maintenance expenses.

- A $46 million decrease in costs associated with the production of our equity NGLs reflecting a decrease of $34 million associated with a 25 percent decrease in average natural gas prices and a $12 million decrease from lower NGL volumes.

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

The increase in Midstream s *segment profit* includes:

- A $14 million increase in NGL margins reflecting:
  - A $20 million increase in the onshore businesses NGL margins reflecting a $35 million increase related to favorable commodity price changes including a 25 percent decrease in average natural gas prices and a slight increase in average NGL prices, partially offset by a $15 million decrease related to lower NGL equity volumes. NGL equity volumes sold were lower due primarily to lower recoveries during downtime for maintenance and severe winter weather conditions limiting third-party producers ability to deliver gas.

  - A $6 million decrease in the Gulf Coast businesses NGL margins reflecting a $12 million decrease in NGL equity volumes, partially offset by a $6 million increase related to a 21 percent decrease in average natural gas prices and an 11 percent increase in average NGL prices. NGL equity volumes sold were lower due primarily to a change in a major contract from keep-whole to percent-of-liquids processing.
- A $12 million increase in fee revenues as previously discussed.

- A $12 million increase in margins related to the marketing of NGLs and crude primarily due to more favorable changes in pricing while product was in transit in 2011 as compared to 2010.
- A $22 million increase in operating costs as previously discussed.

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Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

For 2011, we expect operating results and cash flows to be higher than 2010 levels due to the combination of expected higher energy commodity margins 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 short-term 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.

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 2011:

- We increased our per-unit quarterly distribution with respect to the first quarter of 2011 from $0.7025 to $0.7175.
- We expect to increase quarterly limited partner cash distributions by approximately 6 percent to 10 percent annually.
- We have $458 million and $325 million of debt maturing in 2011 and 2012, respectively. We anticipate funding these maturities with new debt issuances.
- 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 $1.75 billion and $2.1 billion in 2011.
- During April 2011, we agreed to acquire from Williams an additional 24.5 percent interest in Gulfstream in exchange for aggregate consideration of $297 million of cash, 632,584 of our limited partner units, and an increase in the capital account of our general partner to allow it to maintain its 2 percent general partner interest. We expect to fund the cash consideration for this transaction through our credit facility. Upon completing this transaction, which we expect to close during the second quarter of 2011, we will hold a 49 percent interest in Gulfstream.

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 2011. 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:

Management s Discussion and Analysis (Continued)

Maintenance and expansion capital expenditures;

Payment of debt maturities (pursuant to expected issuances of new long-term debt);

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.

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;

Limited availability of capital due to a change in our financial condition, interest rates, market or industry conditions;

Sustained reductions in energy commodity margins from expected 2011 levels;

Physical damages to facilities, especially damage to offshore facilities by named windstorms.

Available Liquidity

		March 31, 2011 (Millions)
Cash and cash equivalents	$	232
Available capacity under our $1.75 billion three-year senior unsecured credit facility (expires February 17, 2013) (1)		1,750
	$	1,982

(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.

We expect that our available liquidity will be reduced during the second quarter of 2011 related to our acquisition of an additional interest in Gulfstream.

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 Liquid Products LP, Discovery Producer Services LLC, Gulfstream, Laurel Mountain Midstream, LLC, and Overland Pass Pipeline Company LLC.

Omnibus Agreement with Williams

In connection with the Dropdown in February 2010, we entered into an omnibus agreement with The Williams Companies, Inc. (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

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Management s Discussion and Analysis (Continued)

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 are 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.

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 16, 2011	Under review for possible upgrade	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 March 31, 2011, we estimate that a downgrade to a rating below investment grade would require us to post up to $67 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, including (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, including (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 and purchase of investments for 2011. These amounts reflect total increases to property, plant, and equipment, including accrued amounts, and investments:

Segment	Maintenance 2011 Estimate	Maintenance Three Months Ended March 31, 2011	Expansion 2011 Estimate	Expansion Three Months Ended March 31, 2011	Total 2011 Estimate	Total Three Months Ended March 31, 2011
			(Millions)			
Gas Pipeline	$ 305-330	$ 21	$ 560-610	$ 84	$ 865-940	$ 105
Midstream	165-185	13	860-1,090	60	1,025-1,275	73
Total	$ 470-515	$ 34	$ 1,420-1,700	$ 144	$ 1,890-2,215	$ 178

See Results of Operations Segments, Gas Pipeline and Midstream 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 $0.7025 to $0.7175 per unit, which resulted in a first-quarter 2011 distribution of approximately $276 million that will be paid on May 13, 2011, to the general and limited partners of record at the close of business on May 6, 2011.

Sources (Uses) of Cash

	Three months ended March 31, 2011	Three months ended March 31, 2010
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 511	$ 596
Financing activities	(269)	2,920
Investing activities	(197)	(3,541)
Increase (decrease) in cash and cash equivalents	$ 45	$ (25)

Operating activities

Net cash provided by operating activities for the three months ended March 31, 2011, decreased from the same period in 2010 primarily due to the timing of settling certain affiliate balances.

Financing activities

Significant transactions include:

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

$305 million in distributions to Williams primarily related to the contributed entities prior to the closing of the Dropdown in February 2010;

$268 million and $34 million in 2011 and 2010, respectively, related to quarterly cash distributions paid to

Management s Discussion and Analysis (Continued)

limited partner unit holders and our general partner;

$250 million received from revolver borrowings on our $1.75 billion unsecured credit facility in February 2010 to repay a term loan outstanding under our credit agreement which expired at the closing of the Dropdown in February 2010.

Investing activities

Significant transactions include:

$3.4 billion related to the cash consideration paid to Williams related to the Dropdown in February 2010;

Capital expenditures in 2011 and 2010 totaled $156 million and $120 million, respectively.

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

We have various other guarantees and commitments which are disclosed in Notes 6 and 7 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

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Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first three months of 2011.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of 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 6 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 less than $1 million at March 31, 2011 and zero at December 31, 2010.

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 is also 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 general partner s Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

First-Quarter 2011 Changes in Internal Controls

There have been no changes during the first quarter of 2011 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 7 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.

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Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2010, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed, except as set forth below:

Our costs of testing, maintaining or repairing our facilities may exceed our expectations and the FERC or competition in our markets may not allow us to recover such costs in the rates we charge for our services.

We could experience unexpected leaks or ruptures on our gas pipeline system, or be required by regulatory authorities to test or undertake modifications to our systems that could result in a material adverse impact on our business, financial condition and results of operations if the costs of testing, maintaining or repairing our facilities exceed current expectations and the FERC or competition in our markets do not allow us to recover such costs in the rates we charge for our service. For example, in response to a recent third-party pipeline rupture, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing, or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs.

Cost reimbursements due to our general partner and its affiliates will reduce cash available to pay distributions to unitholders.

We will reimburse our general partner and its affiliates, including Williams, for various general and administrative services they provide for our benefit, including costs for rendering administrative staff and support services to us, and overhead allocated to us. Our general partner determines the amount of these reimbursements in its sole discretion. Payments for these services will be substantial and will reduce the amount of cash available for distributions to unitholders. Furthermore, Williams, which owns our general partner, recently announced a plan to separate its exploration and production business into a newly formed separate publicly-traded corporation. While Williams retains the discretion to determine whether and when to complete this reorganization plan, the spin-off of Williams' exploration and production business could significantly increase the costs of the general and administrative services provided to us. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

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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, 6, and 7 (filed on February 21, 2011 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)

May 5, 2011

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