Williams Partners L.P.
Form 10-Q
May 05, 2010

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, 2010

OR

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

For the transition period from __________ to __________

Commission file number 1-32599

WILLIAMS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

DELAWARE	20-2485124
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER TULSA, OKLAHOMA	74172-0172
(Address of Principal Executive Offices)	(Zip Code)

(918) 573-2000
(Registrant s Telephone Number, Including Area Code)
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 pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or such shorter period that the registrant was required to submit and post such files). Yes o 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 52,777,452 common units and 203,000,000 Class C units outstanding as of May 4, 2010.

Williams Partners L.P.
Index

Certain matters discussed in this report include forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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

1

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

- Whether we have sufficient cash from operations to enable us to maintain current levels of cash distributions or to pay the minimum quarterly distribution following establishment of cash reserves and payment of fees and expenses, including payments to our general partner;

- Availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and the availability and cost of capital;

- Inflation, interest rates and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);

- The strength and financial resources of our competitors;

- Development of alternative energy sources;

- The impact of operational and development hazards;

- Costs of, changes in, or the results of laws, government regulations (including proposed climate change legislation), environmental liabilities, litigation and rate proceedings;

- Our allocated costs for defined benefit pension plans and other postretirement benefit plans sponsored by our affiliates;

- Changes in maintenance and construction costs;

- Changes in the current geopolitical situation;

- Our exposure to the credit risks of our customers;

- Risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;

- Risks associated with future weather conditions;

- Acts of terrorism; and

- Additional risks described in our filings with the Securities and Exchange Commission (SEC).

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

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

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2009.

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

Williams Partners L.P.
Consolidated Statement of Income
(Unaudited)

	Three months ended March 31, 2010	2009*
	(Millions, except per-unit amounts)	
Revenues:		
Gas Pipeline	$ 407	$ 401
Midstream Gas & Liquids	1,051	558
Intercompany eliminations		(2)
Total revenues	1,458	957
Segment costs and expenses:		
Costs and operating expenses	1,014	643
Selling, general and administrative expenses	59	70
Other income net	(3)	(3)
Segment costs and expenses	1,070	710
General corporate expenses	34	25
Operating income:		
Gas Pipeline	160	164
Midstream Gas & Liquids	228	83
General corporate expenses	(34)	(25)
Total operating income	354	222
Equity earnings	26	5
Interest accrued third-party	(81)	(51)
Interest accrued affiliate		(14)
Interest capitalized	12	14
Interest income third-party		1
Interest income affiliate	3	4
Other income (expense) net	(1)	3
Income before income taxes	313	184
Provision for income taxes		1
Net income	313	183
Less: Net income attributable to noncontrolling interests	6	7
Net income attributable to controlling interests	$ 307	$ 176
Allocation of net income for calculation of earnings per common unit:		
Net income attributable to controlling interests	$ 307	$ 176
Allocation of net income to general partner and Class C units	275	157

Allocation of net income to common units	$ 32	$ 19
Basic and diluted net income per common unit:		
Common units	$ 0.61	$ 0.36
Weighted average number of common units outstanding	52,777,452	52,777,452

* Recast as discussed in Note 1.

See accompanying notes.

3

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

	March 31, 2010	December 31,2009*
	(Millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 128	$ 153
Accounts receivable:		
Trade	372	381
Affiliate	148	6
Inventories	149	129
Regulatory assets	71	77
Other current assets	64	75
Total current assets	932	821
Investments	594	593
Gross property, plant and equipment	15,500	15,416
Less accumulated depreciation	(5,296)	(5,191)
Property, plant and equipment net	10,204	10,225
Regulatory assets, deferred charges and other	406	345
Total assets	$ 12,136	$ 11,984
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 344	$ 356
Affiliate	127	80
Accrued liabilities	235	185
Long-term debt due within one year	9	15
Total current liabilities	715	636
Long-term debt	6,330	2,981
Asset retirement obligations	476	477
Regulatory liabilities, deferred income and other	266	263
Contingent liabilities and commitments (Note 7)		
Equity:		
Common units (52,777,452 units outstanding at March 31, 2010 and December 31, 2009)	1,648	1,631
Class C units (203,000,000 units outstanding at March 31, 2010)	3,683	
General partner	(1,319)	5,647
Accumulated other comprehensive income (loss)	(10)	2
Noncontrolling interests in consolidated subsidiaries	347	347

Total equity	4,349	7,627
Total liabilities and equity	$ 12,136	$ 11,984

* Recast as discussed in Note 1.

See accompanying notes.

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

	Williams Partners L.P. Limited Partners Common	Class C	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
			(Millions)			
Balance — January 1, 2010	$ 1,631	$	$ 5,647	$ 2	$ 347	$ 7,627
Comprehensive income:						
Net income	50	89	168		6	313
Other comprehensive loss:						
Net unrealized losses on cash flow hedges, net of reclassification adjustments				(12)		(12)
Total other comprehensive loss						(12)
Total comprehensive income						301
Cash distributions	(33)		(1)			(34)
Dividends paid to noncontrolling interests					(6)	(6)
Issuance of units (203,000,000 Class C units)		6,946	(6,946)			
Distributions to The Williams Companies, Inc. net		(3,352)	(186)			(3,538)
Other			(1)			(1)
Balance — March 31, 2010	$ 1,648	$ 3,683	$ (1,319)	$ (10)	$ 347	$ 4,349

See accompanying notes.

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

	Three months ended March 31, 2010	2009*
	(Millions)	
OPERATING ACTIVITIES:		
Net income	$ 313	$ 183
Adjustments to reconcile to net cash provided by operations:		
Depreciation and amortization	134	130
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	9	(12)
Inventories	(20)	1
Other assets and deferred charges	24	(5)
Accounts payable	17	(37)
Accrued liabilities	17	(27)
Affiliates net	49	(10)
Other, including changes in noncurrent assets and liabilities	12	31
Net cash provided by operating activities	555	254
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)	(6)
Distributions to limited partners and general partner	(34)	(42)
Distributions to The Williams Companies, Inc net	(262)	
Other net	(17)	(11)
Net cash provided (used) by financing activities	2,963	(59)
INVESTING ACTIVITIES:		
Purchase of Contributed Entities	(3,420)	
Property, plant and equipment:		
Capital expenditures	(122)	(159)
Net proceeds from dispositions	6	
Changes in notes receivable from parent		(71)
Other net	(7)	(6)
Net cash used by investing activities	(3,543)	(236)
Decrease in cash and cash equivalents	(25)	(41)
Cash and cash equivalents at beginning of period	153	133

Cash and cash equivalents at end of period	$ 128	$ 92

* Recast as discussed in Note 1.

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. Williams currently owns an approximate 82 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, 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 audited supplemental consolidated financial statements and notes thereto included in our Form 8-K, filed April 20, 2010, for the year ended December 31, 2009. The accompanying 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, 2010, results of operations for the three months ended March 31, 2010 and 2009 and cash flows for the three months ended March 31, 2010 and 2009. We eliminated all intercompany transactions and reclassified certain amounts to conform to the current classifications.

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

Basis of Presentation

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

This contribution was made in exchange for aggregate consideration of:

$3.5 billion in cash, less certain expenses incurred by us, which we financed by issuing $3.5 billion of senior unsecured notes (see Note 3).

203 million of our Class C limited partnership units, which are identical to our common limited partnership units except that for the distribution with respect to the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. The Class C units will automatically convert into our common limited partnership units on May 10, 2010. The Class C units have been recorded at an amount equal to the carrying amount of the contributed assets and liabilities less the cash consideration paid to Williams and the increase in the capital account of our general partner. The cash consideration will be reduced by approximately $144 million related to the net cash received in February by Williams related to the contributed entities. At March 31, 2010, this receivable from Williams is reflected in *accounts receivable affiliate* in the *Consolidated Balance Sheet*.

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

Notes (Continued)

These transactions are reflected in these consolidated financial statements. Because the acquired entities were affiliates of Williams at the time of the acquisition, this transaction is accounted for as a combination of entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the acquired entities are combined with ours at their historical amounts. The effect of recasting our financial statements to account for this common control transaction increased net income $164 million for the three months ended March 31, 2009. This acquisition did not impact historical earnings per limited partner unit as pre-acquisition earnings of the Contributed Entities were allocated to our general partner.

Description of Business

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

Gas Pipeline includes Transcontinental Gas Pipe Line Company, LLC (Transco) and a 65 percent interest in Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 TBtu of natural gas and peak-day delivery capacity of approximately 12 MMdt of natural gas. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 million Dth per day of natural gas. Gas Pipeline also includes our indirect 45.7 percent limited partner interest and 2 percent general partner interest in WMZ, which holds the remaining 35 percent interest in Northwest Pipeline.

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

Note 2. Allocation of Net Income and Distributions

The allocation of net income among our general partner, limited partners, and noncontrolling interests as reflected in the *Consolidated Statement of Changes in Equity*, for the three months ended March 31, 2010, is as follows:

	Three months ended March 31, 2010 (Millions)	
Allocation of net income to general partner:		
Net income	$	313
Net income applicable to pre-partnership operations allocated to general partner		(163)
Net income applicable to noncontrolling interests		(6)
Net reimbursable costs charged directly to general partner		(2)
Income subject to 2% allocation of general partner interest		142
General partner s share of net income		2.0%
General partner s allocated share of net income before items directly allocable to general partner interest		3
Incentive distributions paid to general partner*		
Charges allocated directly to general partner		2
Pre-partnership net income allocated to general partner interest		163
Net income allocated to general partner	$	168
Net income	$	313

Net income allocated to general partner		168
Net income allocated to Class C limited partners		89
Net income allocated to noncontrolling interests		6
Net income allocated to common limited partners	$	50

* In the calculation of basic and diluted net income per limited partner unit, the net income allocated to the general partner includes IDRs pertaining to the current reporting period, but paid in the subsequent period. For the three months ended March 31, 2010, the net income allocated to the common units for purposes of calculating net income per common unit was calculated based on an allocation of net income to the respective ownership interests reflective of the cash each interest will receive in our May 14, 2010 cash distribution less each interest s share of the deficit

amount between the May 14, 2010 cash distribution and the net income allocable to the partnership.

Notes (Continued)

The reimbursable general and administrative and other costs represent the costs charged against our income that our general partner is required to reimburse us under the terms of an omnibus agreement.

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

				General Partner		
					Incentive	
Payment Date	Per Unit Distribution	Common Units	Class C Units	2%	Distribution Rights	Total Cash Distribution
2/13/2009	$0.6350	$33	$	$1	$ 8	$ 42
5/15/2009	$0.6350	$33	$	$1	$	$ 34
8/14/2009	$0.6350	$33	$	$1	$	$ 34
11/13/2009	$0.6350	$33	$	$1	$	$ 34
2/12/2010	$0.6350	$33	$	$1	$	$ 34
5/14/2010 (a)	$0.6575	$35	$87	$3	$ 30	$ 155

(a) The Board of Directors of our general partner declared this cash distribution on April 22, 2010, to be paid on May 14, 2010, to unitholders of record at the close of business on May 7, 2010. Distributions to the Class C unitholders and the additional general partner units issued in connection with the closing of the Dropdown, as well as the related incentive distribution rights payment, were prorated to reflect the fact that they were not outstanding during the full quarterly period.

Note 3. Debt and Banking Arrangements

Long-Term Debt

	March 31, 2010	
	Weighted-Average Interest Rate	Balance (1) (Millions)
Unsecured		
3.8% to 8.875% , payable through 2040	6.1%	$ 6,231
Revolving credit loans (2)	3.0%	108
Total long-term debt, including current portion		6,339
Long-term debt due within one year		(9)
Long-term debt		$ 6,330

(1) Certain of our debt agreements contain covenants that restrict or limit, among other things, our ability to create liens supporting indebtedness, sell assets, make certain distributions, repurchase equity, and incur additional debt.

(2) At December 31, 2009, we had a term loan of $250 million, which was repaid in first-quarter 2010 by utilizing our new $1.75 billion credit facility (discussed

below). As of March 31, 2010, loans outstanding under the credit facility are $108 million.

Revolving Credit and Letter of Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion three-year senior unsecured revolving credit facility with Transco and Northwest Pipeline as co-borrowers (Credit Facility). This Credit Facility replaced our unsecured $450 million credit facility, comprised of a $200 million revolving credit facility and a $250 million term loan, which was terminated as part of the Dropdown. At the closing, we utilized $250 million of the Credit Facility to repay the outstanding term loan. As of March 31, 2010, loans outstanding under the Credit Facility were reduced to $108 million using available cash. The Credit Facility expires February 15, 2013, and may, under certain conditions, be increased by up to an additional $250 million. The full amount of the Credit Facility is available to us to the extent not otherwise utilized by Transco and Northwest Pipeline. Transco and Northwest Pipeline each have access to borrow up to $400 million under the Credit Facility to the extent not otherwise utilized by us. Each time funds are borrowed, the borrower may choose from two methods of calculating interest: a fluctuating base rate equal to Citibank N.A. s adjusted base rate plus an applicable margin, or a periodic fixed rate equal to LIBOR plus an applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) Citibank N.A. s publicly announced base rate, and (iii) one-month LIBOR plus 1.0 percent. We are required to pay a

Notes (Continued)
commitment fee (currently 0.5 percent) based on the unused portion of the Credit Facility. The applicable margin and the commitment fee are based on the specific borrower s senior unsecured long-term debt ratings. The Credit Facility contains various covenants that limit, among other things, a borrower s and its respective subsidiaries ability to incur indebtedness, grant certain liens supporting indebtedness, merge or consolidate, sell all or substantially all of its assets, enter into certain affiliate transactions, make certain distributions during an event of default and allow any material change in the nature of its business. Significant financial covenants under the Credit Facility include:

Our ratio of debt to EBITDA (each as defined in the Credit Facility) must be no greater than 5 to 1.

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

Each of the above ratios will be tested, beginning June 30, 2010, at the end of each fiscal quarter, and the debt to EBITDA ratio will be measured on a rolling four-quarter basis (with the first full year measured on an annualized basis).

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

At March 31, 2010, $108 million in loans are outstanding and no letters of credit are issued under the credit facility.

Issuances

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

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

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

As part of the issuance of the $3.5 billion unsecured notes, we entered into registration rights agreements with the initial purchasers of the notes. We are obligated to file a registration statement for an offer to exchange the notes for a new issue of substantially identical notes registered under the Securities Act of 1933, as amended, within 180 days from closing and to use our commercially reasonable efforts to cause the registration statement to be declared effective within 270 days after closing and to consummate the exchange offer within 30 business days after such effective date. We are required to provide a shelf registration statement to cover resales of the notes under certain circumstances. If we fail to fulfill these obligations, additional interest will accrue on the affected securities. The rate of additional interest will be 0.25 percent per annum on the principal amount of the affected securities for the first 90-day period immediately following the occurrence of default, increasing by an additional 0.25 percent per annum with respect to each subsequent 90-day period thereafter, up to a maximum amount for all such defaults of 0.5 percent annually. Following the cure of any registration defaults, the accrual of additional interest will cease.

Note 4. Inventories

	March 31, 2010	**December 31, 2009**

	(Millions)	
Natural gas liquids	$ 48	$ 44
Natural gas in underground storage	35	20
Materials, supplies, and other	66	65
	$ 149	$ 129

Notes (Continued)

Note 5. Fair Value Measurements

Fair value is the amount received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange traded.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. The instruments included in Level 2 consist primarily of over-the-counter instruments such as natural gas forward contracts and swaps.

Level 3 Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments that are valued utilizing unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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, 2010				**December 31, 2009**			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
	(Millions)				**(Millions)**			
Assets:								
ARO Trust Investments (see Note 6)	$ 25	$	$	$ 25	$ 22	$	$	$ 22
Energy derivatives			6	6			2	2
Total assets	$ 25	$	$ 6	$ 31	$ 22	$	$ 2	$ 24

Liabilities:								
Energy derivatives	$	$ 9	$ 2	$ 11	$	$	$ 2	$ 2
Total liabilities	$	$ 9	$ 2	$ 11	$	$	$ 2	$ 2

Notes (Continued)

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit), and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Forward and swap contracts included in Level 2 are valued using an income approach including present value techniques. Significant inputs into our Level 2 valuations include commodity prices and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

The tenure of our energy derivatives portfolio is relatively short with all of our derivatives expiring in the next 12 months. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes and documented on a monthly basis.

Certain instruments trade in less active markets with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. Certain inputs into the model are generally observable, such as interest rates, whereas natural gas liquids commodity prices are considered unobservable. The instruments included in Level 3 consist primarily of natural gas liquids swaps and forward contracts.

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers between Level 1 and Level 2 occurred during the period ended March 31, 2010. The following tables present a reconciliation of changes in the fair value of net energy derivatives classified as Level 3 in the fair value hierarchy.

Level 3 Fair Value Measurements Using Significant Unobservable Inputs

	Net Energy Derivatives Three months ended March 31,	
	2010	**2009**
	(Millions)	
Beginning balance	$	$ 1
Realized and unrealized gains (losses):		
Included in *net income*	(1)	
Included in other comprehensive income (loss)	5	
Purchases, issuances, and settlements		
Transfers into Level 3		
Transfers out of Level 3		
Ending balance	$ 4	$ 1
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* in our *Consolidated Statement of Income*.

For the periods ended March 31, 2010 and 2009, there were no assets or liabilities measured at fair value on a nonrecurring basis.

Notes (Continued)

Note 6. Financial Instruments, Derivatives and Concentrations of Credit Risk

Financial Instruments

Fair-value methods

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

Cash and cash equivalents*:* The carrying amounts reported in the *Consolidated Balance Sheet* approximate fair value due to the short-term maturity of these instruments.

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

Long-term debt: The fair value of our publicly traded long-term debt is valued using indicative period-end traded bond market prices. Private debt is valued based on market rates and the prices of similar securities with similar terms and credit ratings. At March 31, 2010 and December 31, 2009, approximately 43 percent and 91 percent, respectively, of our long-term debt was publicly traded. (See Note 3.)

Other: Includes current and noncurrent notes receivable.

Energy derivatives: Energy derivatives include forwards and swaps. These are carried at fair value in the *Consolidated Balance Sheet*. See Note 5 for discussion of valuation of our energy derivatives.

Carrying amounts and fair values of our financial instruments

	March 31, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions)			
Asset (Liability)				
Cash and cash equivalents	$ 128	$ 128	$ 153	$ 153
ARO Trust Investments	25	25	22	22
Long-term debt, including current portion	(6,339)	(6,658)	(2,996)	(3,194)
Other	1	1	3	3
Net energy derivatives:				
Energy commodity cash flow hedges affiliate	(6)	(6)	(2)	(2)
Other energy derivatives	1	1	2	2

Energy Commodity Derivatives

Risk management activities

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

We sell NGL volumes received as compensation for certain processing services at different locations throughout the United States. We also buy natural gas to satisfy the required fuel and shrink needed to generate NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices, we may enter into NGL or natural gas swap agreements, financial or physical forward contracts, and financial option contracts to mitigate the price risk on

Notes (Continued)

forecasted sales of NGLs and purchases of natural gas. These cash flow hedges are expected to be highly effective in offsetting cash flows attributable to the hedged risk during the term of the hedge. However, ineffectiveness may be recognized primarily as a result of locational differences between the hedging derivative and the hedged item.

Volumes

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

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

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

The following table depicts the notional quantities of the net long (short) positions in our commodity derivatives portfolio as of March 31, 2010. Natural gas is presented in millions of British Thermal Units (MMBtu) and NGLs are presented in gallons.

Derivative Notional Volumes		**Measurement**	**Fixed Price**	**Basis**
Designated as Hedging Instruments				
Midstream	Risk Management	MMBtu	8,502,500	4,450,000
Midstream	Risk Management	Gallons	(119,784,000)	
Not Designated as Hedging Instruments				
Midstream	Risk Management	Gallons	(2,100,000)	

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 *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 within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements.

	March 31, 2010		**December 31, 2009**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
	(Millions)		**(Millions)**	
Designated as hedging instruments	$ 5	$ 11	$	$ 2
Not designated as hedging instruments	1		2	
Total derivatives	$ 6	$ 11	$ 2	$ 2

The following table presents gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in *accumulated other comprehensive income (loss)* (AOCI) or revenues.

	Three months ended March 31,		
	2010	**2009**	**Classification**
	(Millions)		
Net loss recognized in other comprehensive income (effective portion)	$ (6)	$	AOCI
Net loss reclassified from accumulated other comprehensive income into income (effective portion)	$ (2)	$	Revenues
Gain (loss) recognized in income (ineffective portion)	$	$	Revenues

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness or as a result of reclassifications to earnings following the discontinuance of any cash flow hedges. As of March 31, 2010, we have hedged portions of future cash flows associated with anticipated NGL sales and natural gas purchases for up to one year. Based on recorded values at March 31, 2010, net losses to be

Notes (Continued)

reclassified into earnings within the next 12 months are $6 million. These recorded values are based on market prices of the commodities as of March 31, 2010. Due to the volatile nature of commodity prices and changes in the creditworthiness of counterparties, actual gains or losses realized in the next 12 months 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.

Losses recognized in *revenues* on our energy commodity derivatives not designated as hedging instruments were less than $1 million as of March 31, 2010 and 2009.

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

Credit-risk-related features

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

Guarantees

In addition to the guarantees and payment obligations discussed in Note 7, we have issued guarantees and other similar arrangements as discussed below.

We are required by our revolving credit agreement to indemnify lenders for any taxes required to be withheld from payments due to the lenders and for any tax payments made by the lenders. The maximum potential amount of future payments under these indemnifications is based on the related borrowings and such future payments cannot currently be determined. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications and have no current expectation of a future claim.

At March 31, 2010, we do not expect these guarantees to have a material impact on our future liquidity or financial position. However, if we are required to perform on these guarantees in the future, it may have a material adverse effect on our results of operations.

Note 7. Contingent Liabilities

Environmental Matters

Since 1989, Transco has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At March 31, 2010, we had accrued liabilities of $5 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $1 million, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco s rates.

Notes (Continued)

Beginning in the mid-1980s, Northwest Pipeline evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington s current environmental standards. At March 31, 2010, we have accrued liabilities of $8 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. In September 2009, the EPA announced that it would reconsider those standards. In January 2010, the EPA proposed more stringent standards, which are expected to be final in August 2010. The EPA expects that new eight-hour ozone nonattainment areas will be designated in July 2011. The new standards and nonattainment areas will likely impact the operations of our interstate gas pipelines and cause us to incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet these regulations. We expect that costs associated with these compliance efforts 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 NOVs alleging violations of Clean Air Act requirements at these compressor stations. Transco met with the EPA in May 2008 and submitted its response denying the allegations in June 2008. In July 2009, the EPA requested additional information pertaining to these compressor stations and in August 2009, Transco submitted the requested information.

In April 2007, the New Mexico Environment Department s (NMED) Air Quality Bureau issued a Notice of Violation (NOV) that alleges various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. In December 2007, the NMED proposed a penalty of approximately $3 million. In July 2008, the NMED issued an NOV that alleged air emissions permit exceedances for three glycol dehydrators at one of our compressor facilities and proposed a penalty of approximately $103,000. We are discussing the proposed penalties with the NMED.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant in Colorado and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

Current federal regulations require that certain unlined liquid containment pits located near named rivers and catchment areas be taken out of use, and current state regulations required all unlined, earthen pits to be either permitted or closed by December 31, 2005. Operating under a New Mexico Oil Conservation Division-approved work plan, we have physically closed all of our pits that were slated for closure under those regulations. We are presently awaiting agency approval of the closures for 40 to 50 of those pits. We are also a participant in certain hydrocarbon removal and groundwater monitoring activities associated with certain well sites in New Mexico. Of nine remaining active sites, product removal is ongoing at four and groundwater monitoring is ongoing at each site. As groundwater concentrations reach and sustain closure criteria levels and state regulator approval is received, the sites will be properly abandoned. We expect the remaining sites will be closed within four to seven years.

We are a participant in certain environmental remediation activities associated with soil and groundwater contamination at our Conway storage facilities. These activities relate to four projects that are in various remediation stages including assessment studies, cleanups and/or remedial operations and monitoring. We continue to coordinate with the Kansas Department of Health and Environment (KDHE) to develop screening, sampling, cleanup and monitoring programs. The costs of such activities will depend upon the program scope ultimately agreed to by the KDHE and are expected to be paid over the life of the assets. At March 31, 2010, we had accrued liabilities totaling

$5 million for these costs. Under an omnibus agreement with Williams entered into at the closing of our initial

Notes (Continued)

public offering, Williams agreed to indemnify us for certain Conway environmental remediation costs. At March 31, 2010, approximately $6 million remains available for future indemnification. Payments received under this indemnification are accounted for as a capital contribution to us by Williams as the costs are reimbursed.

Summary of environmental matters

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

Rate Matters

On March 1, 2001, Transco submitted to the Federal Energy Regulatory Commission (FERC) a general rate filing (Docket No. RP01-245) to recover increased costs. All cost of service, throughput and throughput mix, cost allocation and rate design issues in this rate proceeding have been resolved by settlement or litigation. The resulting rates were effective from September 1, 2001 to March 1, 2007. A tariff matter related to storage service in this proceeding has not yet been resolved.

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

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

Safety Matters

The United States Department of Transportation Pipeline and Hazardous Materials Safety Administration rules implementing the Pipeline Safety Improvement Act of 2002 require pipeline operators to implement integrity management programs, including more frequent inspections and other safeguards in areas where the potential consequences of pipeline accidents pose the greatest risk to people and property. In accordance with the final rule, Transco and Northwest Pipeline developed Integrity Management Plans, identified high consequence areas, completed baseline assessment plans, and are on schedule to complete the required assessments within specified timeframes. Currently, Transco and Northwest Pipeline estimate that the cost to perform required assessments and remediation will be primarily capital and range between $150 and $220 million, and between $65 million and $85 million, respectively, over the remaining assessment period of 2010 through 2012. Management considers the costs associated with compliance with the rule to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through their respective rates.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, we were named, along with other subsidiaries of Williams, as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants opposed class certification, and on September 18, 2009, the court denied plaintiffs most recent motion to certify the class. On

Notes (Continued)

October 2, 2009, the plaintiffs filed a motion for reconsideration of the denial. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

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. WMZ is consolidated within the Gas Pipeline segment. (See Note 1.)

Performance Measurement

We currently evaluate segment operating performance based on *segment profit* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses, and equity earnings*. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

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

Gas Pipeline depreciation and operation and maintenance expenses;

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

Notes (Continued)

The following table reflects the reconciliation of *segment revenues* to *revenues* and *segment profit* to *operating income* as reported in the *Consolidated Statement of Income*. It also presents other financial information related to long-lived assets.

	Gas Pipeline	Midstream Gas & Liquids	Eliminations	Total
		(Millions)		
Three months ended March 31, 2010				
Segment revenues:				
External	$ 407	$ 1,051	$	$ 1,458
Internal				
Total revenues	$ 407	$ 1,051	$	$ 1,458
Segment profit	$ 169	$ 245	$	$ 414
Less:				
Equity earnings	9	17		26
Segment operating income	$ 160	$ 228	$	$ 388
General corporate expense				(34)
Total operating income				$ 354
Three months ended March 31, 2009*				
Segment revenues:				
External	$ 401	$ 556	$	$ 957
Internal		2	(2)	
Total revenues	$ 401	$ 558	$ (2)	$ 957
Segment profit	$ 172	$ 80	$	$ 252
Less:				
Equity earnings (loss)	8	(3)		5
Segment operating income	$ 164	$ 83	$	$ 247
General corporate expense				(25)
Total operating income				$ 222

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

	Total Assets	
	March 31,	December 31, 2009*

	2010	
	(Millions)	
Gas Pipeline	$ 7,829	$ 7,711
Midstream Gas & Liquids	4,213	4,122
Other Assets and Eliminations	94	151
Total	$ 12,136	$ 11,984

* Recast as discussed in Note 1.

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

Please read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and related notes included in Item 1 of Part I of this quarterly report.

Recent Developments

The Dropdown

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

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

203 million of our Class C limited partnership units, which are identical to our common limited partnership units except that for the distribution with respect to the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. The Class C units will automatically convert into our common limited partnership units on May 10, 2010.

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

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

WMZ Exchange Offer

We have stated our intention to launch an exchange offer for the publicly traded common units of WMZ at a future date or to propose a merger to WMZ s holders.

Credit Facility

In connection with the Dropdown, we entered into a new $1.75 billion senior unsecured revolving three-year credit facility with Transco and Northwest Pipeline, as co-borrowers with borrowing sublimits of $400 million each, and Citibank, N.A., as administrative agent, and other lenders named therein (Credit Facility). The Credit Facility replaced our previous $450 million senior unsecured credit agreement. At the closing of the Dropdown, we borrowed $250 million under the Credit Facility to repay the term loan outstanding under our previously existing credit facility.

Management s Discussion and Analysis (Continued)

Overview

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

- Gas Pipeline includes Transcontinental Gas Pipe Line Company, LLC (Transco) and a 65 percent interest in Northwest Pipeline GP (Northwest Pipeline), which own and operate a combined total of approximately 13,900 miles of pipelines with a total annual throughput of approximately 2,700 trillion British thermal units (TBtu) of natural gas and peak-day delivery capacity of approximately 12 million dekatherms (MMdt) of natural gas. Gas Pipeline also holds interests in joint venture interstate and intrastate natural gas pipeline systems including a 24.5 percent interest in Gulfstream, which owns an approximate 745-mile pipeline with the capacity to transport approximately 1.26 MMdt per day of natural gas.

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

Company Outlook

We believe we are well positioned to execute on our 2010 business plan and to capture attractive growth opportunities. The economic environment in the latter half of 2009 and continuing into the first quarter of 2010 improved compared to conditions in early 2009. In addition, economic and energy commodity price indicators for 2010 and beyond reflect continued improvement in the economic environment. However, given the potential volatility of these measures, it is reasonably possible that the economy could worsen and/or energy commodity prices could decline, negatively impacting future operating results and increasing the risk of nonperformance of counterparties or impairments of long-lived assets.

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

We continue to invest in our businesses in a way that meets customer needs and enhances our competitive position by:

- Continuing to invest in and grow our gathering and processing and interstate natural gas pipeline systems;

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

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

- Lower than anticipated commodity prices;

- Lower than expected levels of cash flow from operations;

- Availability of capital;

- Counterparty credit and performance risk;

- Decreased volumes from third parties served by our midstream business;

- General economic, financial markets, or industry downturn;

- Changes in the political and regulatory environments;

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

Management s Discussion and Analysis (Continued)

We continue to address these risks through utilization of commodity hedging strategies, disciplined investment strategies, and maintaining ample liquidity from cash and cash equivalents and unused revolving credit facility capacity.

Fair Value Measurements

Certain of our energy derivative assets and liabilities and other assets trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. At March 31, 2010, 19 percent of total assets and 18 percent of total liabilities measured at fair value on a recurring basis are included in Level 3. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At March 31, 2010, the credit reserve is significantly less than $1 million on both our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At March 31, 2010, all of our derivatives portfolio expires in the next 12 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at March 31, 2010, consist primarily of natural gas liquids swaps and forward contracts used to manage the price risk of future natural gas liquid sales. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices.

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, 2010, compared to the three months ended March 31, 2009. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31, 2010	Three months ended March 31, 2009	$ Change*	% Change*
	(Millions)			
Revenues	$ 1,458	$ 957	+501	+52%
Costs and expenses:				
Costs and operating expenses	1,014	643	-371	-58%
Selling, general and administrative expenses	59	70	+11	+16%
Other income net	(3)	(3)		
General corporate expenses	34	25	-9	-36%
Total costs and expenses	1,104	735		
Operating income	354	222		
Equity earnings	26	5	+21	NM
Interest accrued net	(69)	(51)	-18	-35%
Interest income	3	5	-2	-40%
Other income (expense) net	(1)	3	-4	NM
Income before income taxes	313	184		
Provision for income taxes		1	+1	+100 %
Net income	313	183		
Less: Net income attributable to noncontrolling interests	6	7	+1	+14%
Net income attributable to controlling interests	$ 307	$ 176		

* + = Favorable change; - = Unfavorable change; NM = A percentage calculation is not meaningful due to change in signs or a percentage change greater

than 200.

Three months ended March 31, 2010 vs. three months ended March 31, 2009

The increase in *revenues* is primarily due to higher natural gas liquid (NGL) and crude oil marketing revenues and higher NGL production revenues at Midstream, reflecting higher average NGL prices.

The increase in *costs and operating expenses* is primarily due to increased NGL and crude oil marketing purchases and NGL production costs at Midstream, reflecting higher average NGL, crude, and natural gas prices.

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

General corporate expenses in 2010 includes $6 million of outside services incurred related to the Dropdown.

The increase in *operating income* reflects $135 million of higher NGL production margins due to an improved energy commodity price environment in the first quarter of 2010 compared to the first quarter of 2009.

The increase in *equity earnings* is primarily due to a $14 million increase from Discovery Producer Services LLC reflecting recovery from the impact of the 2008 hurricanes, new volumes in the first quarter of 2010 from a recently completed expansion, and higher processing margins.

Interest accrued net increased due to the $3.5 billion of senior notes that were issued in February 2010 in conjunction with the Dropdown. See Note 3 of Notes to Consolidated Financial Statements for a discussion of the debt issuance.

Management s Discussion and Analysis (Continued)

Results of Operations Segments

Gas Pipeline

Overview of Three Months Ended March 31, 2010

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

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

Gas Pipeline master limited partnership

As of March 31, 2010, we own approximately 47.7 percent of WMZ, including 100 percent of the general partner, and incentive distribution rights. Considering the presumption of control of the general partner, we consolidate WMZ within our Gas Pipeline segment. Gas Pipeline s segment profit includes 100 percent of WMZ s segment profit.

Outlook for the Remainder of 2010

Expansion Projects

Mobile Bay South

In May 2009, we received approval from the FERC to construct a compression facility in Alabama allowing transportation service to various southbound delivery points. The cost of the project is estimated to be $37 million. The project was placed into service in May 2010 and increased capacity by 253 thousand dekatherms per day (Mdt/d).

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 $241 million. Phase I service is anticipated to begin in July 2010 and will increase capacity by 90 Mdt/d. Phase II service is anticipated to begin in May 2011 and will increase capacity by 218 Mdt/d.

Mobile Bay South II

In November 2009, we filed an application with the FERC to construct additional compression facilities and modifications to existing facilities in Alabama allowing transportation service to various southbound delivery points. Construction is scheduled to begin in August 2010 and is estimated to cost $36 million. The estimated project in-service date is May 2011 and will increase capacity by 380 Mdt/d.

Sundance Trail

In November 2009, we received approval from the FERC to construct approximately 16 miles of 30-inch pipeline between our existing compressor stations in Wyoming. The project also includes an upgrade to our existing compressor station and is estimated to cost $60 million. The estimated in-service date is November 2010 and will increase capacity by 150 Mdt/d.

Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three months ended March 31,	
	2010	**2009**
	(Millions)	
Segment revenues	$ 407	$ 401
Segment profit	$ 169	$ 172

Three months ended March 31, 2010 vs. three months ended March 31, 2009

Segment revenues increased primarily due to $6 million higher transportation imbalance settlements (offset in *costs and operating expenses*), a $6 million sale of base gas from an abandoned storage field (offset in *costs and operating expenses*), and an increase in transportation revenues from expansion projects placed into service in 2009 by Transco. These increases are partially offset by a $9 million decrease in other service revenues.

Costs and operating expenses increased $16 million, or 8 percent, primarily due to an increase in costs of $6 million associated with higher transportation imbalance settlements (offset in *segment revenues*), $6 million related to the sale of base gas from an abandoned storage field (offset in *segment revenues*) and $2 million of higher depreciation expenses.

Selling, general and administrative expenses decreased $9 million, or 21 percent, primarily due to lower employee-related expenses, including pension and other postretirement benefits.

Other (income) expense net reflects $3 million of higher project development costs and $3 million related to the over collection of certain employee-related expenses (offset in *segment revenues*) that will be returned to our customers. These expenses are partially offset by a $5 million gain on the sale of base gas from an abandoned storage field.

Segment profit decreased primarily due to the previously described changes.

Midstream Gas & Liquids

Overview of Three Months Ended March 31, 2010

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

Significant events during 2010 include the following:

Perdido Norte

Our Perdido Norte project, in the western deepwater of the Gulf of Mexico, began start-up of operations late in the first quarter of 2010. The project includes a 200 million cubic feet per day (MMcf/d) expansion of our onshore Markham gas processing facility and a total of 184 miles of deepwater oil and gas lines that expand the scale of our existing infrastructure.

Volatile commodity prices

Average per-unit NGL margins in the first quarter of 2010 are significantly higher than the first quarter of 2009 and also higher than the fourth quarter of 2009, benefiting from a period of increasing average NGL prices while abundant natural gas supplies limited the increase in natural gas prices. Benefits from favorable natural gas price differentials in the Rocky Mountain area continued to narrow during the first quarter of 2010 such that realized per-unit margins are only slightly greater than that of the industry benchmarks for natural gas processed in the Henry Hub area and for liquids fractionated and sold at Mont Belvieu, Texas.

Management s Discussion and Analysis (Continued)

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.

Outlook for remainder of 2010

The following factors could impact our business in 2010.

Commodity price changes

We expect per-unit NGL margins in 2010 to be higher than our average per-unit margins in 2009 and our rolling five-year average per-unit NGL margins. NGL price changes have historically tracked somewhat with changes in the price of crude oil, although NGL, crude and natural gas prices are highly volatile and difficult to predict. NGL margins are highly dependent upon continued demand within the global economy. Forecasted domestic and global demand for polyethylene, or plastics, has been impacted by the weakness in the global economy. In addition, projected new third-party international ethylene production capacity may lower future demand for domestic ethylene. 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 19 percent of our anticipated NGL sales volumes and an approximate corresponding portion of anticipated shrink gas requirements for the remainder of 2010. The combined impact of these energy commodity derivatives will provide a margin on the hedged volumes of $167 million. The following table presents our energy commodity derivatives, including derivatives entered into as of April 30, 2010.

Management s Discussion and Analysis (Continued)

	Period	Volumes Hedged	Weighted Average Hedge Price (per gallon)
Designated as hedging instruments:			
NGL sales ethane (million gallons)	April September 2010	21.0	$ 0.68
NGL sales propane (million gallons)	April December 2010	84.8	$ 1.16
NGL sales isobutane (million gallons)	April December 2010	16.7	$ 1.53
NGL sales normal butane (million gallons)	April December 2010	25.8	$ 1.49
NGL sales natural gasoline (million gallons)	April December 2010	35.2	$ 1.83
			(per MMbtu)
Natural gas purchases (TBtu)	April December 2010	15.8	$ 4.67

Gathering, processing, and NGL sales volumes

The growth of natural gas supplies supporting our gathering and processing volumes are impacted by producer drilling activities. Our customers are generally large producers and we have not experienced and do not anticipate an overall significant decline in volumes due to reduced drilling activity.

In our onshore businesses, we expect higher fee revenues, NGL volumes, depreciation expense and operating expenses in 2010 compared to 2009 as our Willow Creek facility moves into a full year of operation, and our expansion at Echo Springs is completed late in 2010.

We expect fee revenues, NGL volumes, depreciation expense, and operating expenses in our Gulf Coast businesses to increase from 2009 levels with our new Perdido Norte expansion operations which began start-up of operations late in the first quarter of 2010. Increased volumes from our Perdido Norte expansion are expected to be partially offset by lower volumes in other Gulf Coast areas due to expected changes in gas processing contracts, as described below, and natural declines.

Certain of our gas processing contracts contain provisions that allow customers to periodically elect processing services on either a fee basis, keep-whole, or percent-of-liquids basis. When customers switch from keep-whole to percent-of liquids or fee-based processing, our NGL equity sales volumes are reduced. Our per-unit NGL margins increase when customers switch from keep-whole to percent-of-liquids processing because we receive a portion of the extracted NGLs with no natural gas BTU replacement cost.

Expansion Projects

Ongoing major expansion projects include:

Additional processing and NGL production capacities at our Echo Springs facility and related gathering system expansions in the Wamsutter area of Wyoming, which we expect to be in service in the fourth quarter of 2010.

A 28-mile natural gas gathering pipeline in the Marcellus Shale region which we will construct and operate in conjunction with a long-term agreement with a major producer. Construction on the 20-inch pipeline, which will deliver to the Transco pipeline, is expected to begin in the latter part of 2010, and be completed during 2011.

Additional capital to be invested within our Laurel Mountain joint venture to grow the existing gathering infrastructure with additional pipeline miles, compression, and well-connects in 2010 and beyond.

Management s Discussion and Analysis (Continued)

Period-Over-Period Operating Results

	Three Months Ended March 31,	
	2010	**2009**
	(Millions)	
Segment revenues	$ 1,051	$ 558
Segment profit	$ 245	$ 80

Three months ended March 31, 2010 vs. three months ended March 31, 2009

The increase in *segment revenues* is largely due to:

A $293 million increase in marketing revenues primarily due to higher average NGL and crude prices. These changes are offset by similar changes in marketing purchases.

A $188 million increase in revenues associated with the production of NGLs reflecting an increase of $164 million associated with a 98 percent increase in average NGL per-unit sales prices and an increase of $24 million associated with a 22 percent increase in ethane volumes sold and a 5 percent increase in non-ethane volumes sold.

A $7 million increase in fee revenues primarily due to new fees for processing natural gas production at Willow Creek.

Segment costs and expenses increased $348, or 73 percent, million primarily as a result of:

A $294 million increase in marketing purchases primarily due to higher average NGL and crude prices. These changes are offset by similar changes in marketing revenues.

A $53 million increase in costs associated with the production of NGLs reflecting an increase of $40 million associated with a 38 percent increase in average natural gas prices and an increase of $13 million associated with a 15 percent increase in gas volumes for BTU replacement cost and plant fuel.

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

The increase in Midstream s *segment profit* includes:

A $135 million increase in NGL margins reflecting:

A $102 million increase in the onshore businesses NGL margins reflecting a 102 percent increase in average NGL prices, partially offset by an increase in production costs reflecting a 42 percent increase in average natural gas prices. NGL equity volumes were 5 percent higher due primarily to new production at Willow Creek.

A $33 million increase in the Gulf Coast businesses NGL margins reflecting a $29 million increase in related commodity price changes including an 80 percent increase in average NGL prices, partially offset by a 17 percent increase in average natural gas prices. NGL equity volumes sold were 67 percent higher reflecting a 94 percent increase in ethane volumes sold and a 44 percent increase in non-ethane volumes sold due primarily to low recoveries in the first quarter of 2009 driven by unfavorable NGL economics and decreasing inventory in the first quarter of 2010 compared to increasing inventory in the first quarter of 2009.

A $20 million increase in equity earnings, primarily due to a $14 million increase from Discovery Producer Services LLC due primarily to recovery from the impact of the 2008 hurricanes, new volumes in the first quarter of 2010 from a recently completed expansion and higher processing margins.

A $7 million increase in fee revenues primarily due to new fees for processing natural gas production at Willow Creek.

Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition and Liquidity

Outlook

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

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

We believe we have, or have access to, the financial resources and liquidity necessary to meet our requirements for working capital, capital and investment expenditures, unitholder distributions and debt service payments while maintaining a sufficient level of liquidity. In particular, we note the following for 2010:

- We increased our per-unit quarterly distribution from $0.6350 to $0.6575 beginning with the distribution with respect to first quarter of 2010.
- We expect to fund capital and investment expenditures, debt service payments, distributions to unitholders and working capital requirements primarily through cash flow from operations, cash and cash equivalents on hand, cash proceeds from common unit and/or long-term debt issuances and utilization of our revolving credit facility as needed.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses in 2010. Our internal and external sources of liquidity include:

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

We anticipate our more significant uses of cash to be:

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

Management s Discussion and Analysis (Continued)

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

- Lower than expected levels of cash flow from operations.
- Sustained reductions in energy commodity prices from expected 2010 levels.
- Physical damages to facilities, especially damage to offshore facilities by named windstorms for which our aggregate policy limit is $75 million in the event of a material loss.

Available Liquidity

		March 31, 2010 (Millions)
Cash and cash equivalents	$	128
Available capacity under our $1.75 billion three-year senior unsecured credit facility (expires February 15, 2013) (1)		1,642
	$	1,770

(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 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 us.

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, Discovery, Gulfstream and Laurel Mountain.

Omnibus Agreement with Williams

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

Credit Facility

At March 31, 2010, we have a $1.75 billion three-year senior unsecured revolving credit facility (Credit Facility) with Transco and Northwest Pipeline, as co-borrowers, and Citibank, N.A. as the administrative agent, and certain other lenders named therein. The full amount of the Credit Facility is available to us, to the extent not otherwise utilized by Transco and Northwest Pipeline, and may 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 us. We utilized $250 million of the Credit Facility to repay a term loan that was outstanding under our previous credit facility. As of March 31, 2010, loans outstanding under the Credit Facility were reduced to $108 million using available cash.

Management s Discussion and Analysis (Continued)

Interest on borrowings under the Credit Facility is payable at rates per annum equal to, at the option of the borrower: (1) a fluctuating base rate equal to Citibank, N.A. s adjusted base rate plus the applicable margin or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The adjusted base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) Citibank N.A. s publicly announced base rate and (iii) one-month LIBOR plus 1.0 percent. We pay a commitment fee (currently 0.5 percent) based on the unused portion of the Credit Facility. The applicable margin and the commitment fee are determined by reference to a pricing schedule based on the borrower s senior unsecured debt ratings.

In addition, we are required to maintain a ratio of debt to EBITDA (each as defined in the Credit Facility) of no greater than 5 to 1 for us and our consolidated subsidiaries. For each of Transco and Northwest Pipeline and their respective consolidated subsidiaries, the ratio of debt to capitalization (defined as net worth plus debt) is not permitted to be greater than 55 percent. Each of the above ratios will be tested, beginning June 30, 2010, at the end of each fiscal quarter, and the debt to EBITDA ratio will be measured on a rolling four-quarter basis (with the first full year measured on an annualized basis).

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

Credit Ratings

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

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

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

With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. A Ba rating indicates an obligation that is judged to have speculative elements and is subject to substantial credit risk. 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. A BB rating from Fitch indicates that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. 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, 2010, we estimate that a downgrade to a rating below investment grade would require us to post up to $46 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 include (1) capital expenditures made to replace partially or fully depreciated assets in order to maintain the existing operating capacity of our assets and to extend their useful lives, (2) expenditures which are mandatory and/or essential to comply with laws and regulations and maintain the reliability of our operations, and (3) certain well connection expenditures.

Management s Discussion and Analysis (Continued)

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

In addition to the classifications described above, it should be noted that substantially all of our expected capital expenditures for 2010 should be viewed as nondiscretionary from a liquidity perspective as a result of contractual obligations.

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

	Maintenance		Expansion		Total	
Segment	**Total Year Estimate**	**Through March 31, 2010**	**Total Year Estimate**	**Through March 31, 2010**	**Total Year Estimate**	**Through March 31, 2010**
Gas Pipeline	$ 210 $230	$ 21	$ 340 $370	$ 24	$ 550 $600	$ 45
Midstream	$ 105 $125	$ 11	$ 320 $500	$ 49	$ 425 $625	$ 60
Total	$ 315 $355	$ 32	$ 660 $870	$ 73	$ 975 $1,225	$ 105

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 increased our quarterly distribution from $0.6350 to $0.6575 per unit effective with our distribution with respect to the first quarter of 2010. As part of the consideration for the Dropdown, we issued 203 million Class C limited partnership units to Williams, which are identical to our common limited partnership units except that for the first quarter of 2010 they will receive a prorated quarterly distribution since they were not outstanding during the full quarterly period. These Class C units will automatically convert into our common limited partnership units on May 10, 2010. The full amount of our next quarterly distribution will be $154.9 million, which will be paid on May 14, 2010, to the general and limited partners of record at the close of business on May 7, 2010.

Sources (Uses) of Cash

	Three months ended March 31,	
	2010	**2009**
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 555	$ 254
Investing activities	(3,543)	(236)
Financing activities	2,963	(59)
Decrease in cash and cash equivalents	$ (25)	$ (41)

Operating Activities

Net cash provided by operating activities increased $301 million in 2010 as compared to 2009 primarily due to higher operating income.

Investing Activities

Investing activities in 2010 includes $3.4 billion related to the cash consideration paid in the Dropdown transaction. Capital expenditures in 2010 and 2009 totaled $122 million and $159 million, respectively.

Financing Activities

Net cash provided by financing activities in 2010 includes $3.5 billion of net proceeds from the issuance of senior unsecured notes.

Off-Balance Sheet Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at March 31, 2010.

Item 3
Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are commodity price risk and interest rate risk.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of NGLs 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 changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. (Please read Note 5, Fair Value Measurements, of our 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 natural gas liquid sales and natural gas purchases.

The value at risk was $1.8 million at March 31, 2010 and $0.1 million at December 31, 2009.

Substantially all of the derivative contracts included in our value-at-risk calculation are accounted for as cash flow hedges. Any change in the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

Interest Rate Risk

The Dropdown and related debt issuance had a significant impact on our debt portfolio. (See Note 3 of Notes to Consolidated Financial Statements.)

Item 4
Controls and Procedures

Our management, including our general partner s Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Williams Partners L.P. have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner s Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our management concluded that these Disclosure Controls are effective at a reasonable assurance level.

First-Quarter 2010 Changes in Internal Controls

As discussed in Note 1 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, in the first quarter, in exchange for consideration, The Williams Companies, Inc., except for certain operations, contributed to us the ownership interest in the entities comprising its Gas Pipeline and Midstream Gas & Liquids businesses to the extent not already owned by us. As a result beginning this quarter, our evaluation includes these operations.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 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.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2009, includes certain risk factors that could materially affect our business, financial condition or future results. Those Risk Factors have not materially changed.

Item 6. Exhibits

Exhibit No.	Description
Exhibit 2.5	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, and 6 (filed on February 25, 2010 as Exhibit 3.3 to Williams Partners L.P. s annual report on Form 10-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.1	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Registration Rights Agreement, dated as of February 9, 2010, among Williams Partners L.P. and Barclays Capital Inc. and Citigroup Global Markets Inc., each acting on behalf of themselves and the initial purchasers listed on Schedule I thereto (filed on February 10, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Limited Call Right Forbearance Agreement, dated as of February 17, 2010, by and between Williams Partners L.P. and Williams Partners GP LLC (filed on February 22, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.3	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline s 7.125% Debentures, due 2025 (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline Corporation s Form S-3 (File No. 033-62639)) and incorporated herein by reference.
Exhibit 4.4	Indenture, dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline s $175 million aggregate principal

amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File. No. 001-07414) and incorporated herein by reference.

Exhibit No.	Description
Exhibit 4.5	Indenture, dated as of April 5, 2007, between Northwest Pipeline Corporation and The Bank of New York (filed on April 5, 2007 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File No. 001-07414)) and incorporated herein by reference.
Exhibit 4.6	Indenture, dated May 22, 2008, between Northwest Pipeline GP and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Northwest Pipeline GP s Form 8-K File No. 001-07414)) and incorporated herein by reference.
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Exhibit 4.9	Indenture, dated as of August 27, 2001, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed on November 8, 2001 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form S-4 (File No. 333-72982)) and incorporated herein by reference.
Exhibit 4.10	Indenture, dated as of July 3, 2002, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A., as Trustee (filed August 14, 2002 as Exhibit 4.1 to The Williams Companies Inc. s Form 10-Q (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.11	Indenture, dated as of April 11, 2006, between Transcontinental Gas Pipe Line Corporation and JPMorgan Chase Bank, N.A., as Trustee with regard to Transcontinental Gas Pipe Line s $200 million aggregate principal amount of 6.4% Senior Note due 2016 (filed on April 11, 2006 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
Exhibit 4.12	Indenture, dated May 22, 2008, between Transcontinental Gas Pipe Line Corporation and The Bank of New York Trust Company, N.A., as Trustee (filed on May 23, 2008 as Exhibit 4.1 to Transcontinental Gas Pipe Line Corporation s Form 8-K (File No. 001-07584)) and incorporated herein by reference.
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Exhibit No.	Description
Exhibit 10.1	Omnibus Agreement, dated as of February 17, 2010, by and between The Williams Companies, Inc. and Williams Partners L.P. (filed on February 22, 2010 as Exhibit 10.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.2	Conveyance, Contribution and Assumption Agreement, dated as of February 17, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P. and Williams Partners Operating LLC (filed on February 22, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.3	Amendment No. 1 to Amended and Restated Limited Liability Company Agreement of Wamsutter LLC, dated as of February 17, 2010, by and between Williams Field Services Company, LLC and Williams Partners Operating LLC (filed on February 22, 2010 as Exhibit 10.4 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 10.4	Administrative Services Agreement between Northwest Pipeline Services LLC and Northwest Pipeline GP, dated October 1, 2007 (filed on January 30, 2008 as Exhibit 10.1 to Williams Pipeline Partners L.P. s Form 8-K (File No. 001-33917) and incorporated herein by reference.
Exhibit 10.5	Administrative Services Agreement, dated as of February 17, 2010, by and between Transco Pipeline Services LLC and Transcontinental Gas Pipe Line Company, LLC (filed on February 22, 2010 as Exhibit 10.3 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
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Exhibit 12	Computation of Ratio of Earnings to Fixed Charges.*
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Exhibit 31.2	Rule 13a-14(a)/15d-14(a) Certification of Chief Financial Officer.*
Exhibit 32	Section 1350 Certifications of Chief Executive Officer and Chief Financial Officer.**

* Filed herewith.

** Furnished herewith.

SIGNATURES

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, 2010

EXHIBIT INDEX

Exhibit No.	Description
Exhibit 2.5	Contribution Agreement, dated as of January 15, 2010, by and among Williams Energy Services, LLC, Williams Gas Pipeline Company, LLC, WGP Gulfstream Pipeline Company, L.L.C., Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and, for a limited purpose, The Williams Companies, Inc, including exhibits thereto (filed on January 19, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.1	Certificate of Limited Partnership of Williams Partners L.P. (filed on May 2, 2005 as Exhibit 3.1 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.2	Certificate of Formation of Williams Partners GP LLC (filed on May 2, 2005 as Exhibit 3.3 to Williams Partners L.P. s registration statement on Form S-1 (File No. 333-124517)) and incorporated herein by reference.
Exhibit 3.3	Amended and Restated Agreement of Limited Partnership of Williams Partners L.P. (including form of common unit certificate), as amended by Amendments Nos. 1, 2, 3, 4, 5, and 6 (filed on February 25, 2010 as Exhibit 3.3 to Williams Partners L.P. s annual report on Form 10-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 3.4	Amended and Restated Limited Liability Company Agreement of Williams Partners GP LLC (filed on August 26, 2005 as Exhibit 3.2 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.1	Indenture, dated as of February 9, 2010, between Williams Partners L.P. and The Bank of New York Mellon Trust Company, N.A. (filed on February 10, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Registration Rights Agreement, dated as of February 9, 2010, among Williams Partners L.P. and Barclays Capital Inc. and Citigroup Global Markets Inc., each acting on behalf of themselves and the initial purchasers listed on Schedule I thereto (filed on February 10, 2010 as Exhibit 10.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.2	Limited Call Right Forbearance Agreement, dated as of February 17, 2010, by and between Williams Partners L.P. and Williams Partners GP LLC (filed on February 22, 2010 as Exhibit 4.1 to Williams Partners L.P. s current report on Form 8-K (File No. 001-32599)) and incorporated herein by reference.
Exhibit 4.3	Senior Indenture, dated as of November 30, 1995, between Northwest Pipeline Corporation and Chemical Bank, Trustee with regard to Northwest Pipeline s 7.125% Debentures, due 2025 (filed September 14, 1995 as Exhibit 4.1 to Northwest Pipeline Corporation s Form S-3 (File No. 033-62639)) and incorporated herein by reference.
Exhibit 4.4	Indenture, dated as of June 22, 2006, between Northwest Pipeline Corporation and JPMorgan Chase Bank, N.A., as Trustee, with regard to Northwest Pipeline s $175 million aggregate principal

	amount of 7.00% Senior Notes due 2016 (filed on June 23, 2006 as Exhibit 4.1 to Northwest Pipeline Corporation s Form 8-K (File. No. 001-07414) and incorporated herein by reference.
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