Western Gas Partners LP
Form 10-Q
November 02, 2011

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

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

For the quarterly period ended September 30, 2011

Or

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

For the transition period from to

Commission file number: 001-34046

WESTERN GAS PARTNERS, LP

(Exact name of registrant as specified in its charter)

Delaware	**26-1075808**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
1201 Lake Robbins Drive **The Woodlands, Texas**	**77380**
(Address of principal executive offices)	*(Zip Code)*

(832) 636-6000

(Registrant s telephone number, including area code)

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

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if 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

There were 90,140,999 common units outstanding as of October 31, 2011.

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DEFINITIONS

As generally used within the energy industry and in this quarterly report on Form 10-Q, the identified terms have the following meanings:

Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.

Bcf: One billion cubic feet.

Bcf/d: One billion cubic feet per day.

Btu: British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Condensate: A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Cryogenic: The fractionation process in which liquefied gases, such as liquid nitrogen or liquid helium, are used to bring volumes to very low temperatures (below approximately -238 degrees Fahrenheit) to separate natural gas liquids from natural gas. Through cryogenic processing, more natural gas liquids are extracted than when traditional refrigeration methods are used.

Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.

Fractionation: The process of applying various levels of higher pressure and lower temperature to separate a stream of natural gas liquids into ethane, propane, normal butane, isobutane and natural gasoline.

Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.

MBbls/d: One thousand barrels per day.

MMBtu: One million British thermal units.

MMBtu/d: One million British thermal units per day.

MMcf: One million cubic feet.

MMcf/d: One million cubic feet per day.

Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.

Pounds per square inch, absolute: The pressure resulting from a one-pound force applied to an area of one square inch, including local atmospheric pressure. All volumes presented herein are based on a standard pressure base of 14.73 pounds per square inch, absolute.

Residue gas: The natural gas remaining after being processed or treated.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

thousands except per-unit amounts	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010 [(1)]	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 [(1)]
Revenues affiliates				
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 54,126**	$ 48,982	**$ 160,537**	$ 139,740
Natural gas, natural gas liquids and condensate sales	**81,057**	56,933	**201,578**	176,187
Equity income and other, net	**2,298**	1,934	**8,585**	4,976
Total revenues affiliates	**137,481**	107,849	**370,700**	320,903
Revenues third parties				
Gathering, processing and transportation of natural gas and natural gas liquids	**17,747**	11,381	**50,881**	33,029
Natural gas, natural gas liquids and condensate sales	**20,022**	2,954	**61,463**	20,605
Other, net	**613**	867	**1,466**	2,433
Total revenues third parties	**38,382**	15,202	**113,810**	56,067
Total revenues	**175,863**	123,051	**484,510**	376,970
Operating expenses				
Cost of product [(2)]	**68,675**	37,444	**177,877**	117,923
Operation and maintenance [(2)]	**27,012**	19,924	**74,628**	64,798
General and administrative [(2)]	**7,643**	5,970	**21,777**	17,600
Property and other taxes	**4,411**	3,610	**12,632**	10,878
Depreciation, amortization and impairments	**22,650**	19,324	**65,512**	54,683
Total operating expenses	**130,391**	86,272	**352,426**	265,882
Operating income	**45,472**	36,779	**132,084**	111,088
Interest income affiliates	**4,225**	4,225	**12,675**	12,675
Interest expense [(3)]	**(8,931)**	(6,808)	**(22,952)**	(14,547)
Other income (expense), net	**8**	62	**(1,914)**	(2,311)
Income before income taxes	**40,774**	34,258	**119,893**	106,905
Income tax expense	**92**	1,061	**1,715**	9,861
Net income	**40,682**	33,197	**118,178**	97,044
Net income attributable to noncontrolling interests	**3,873**	2,541	**9,665**	7,806

Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238
Limited partners interest in net income:				
Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238
Pre-acquisition net (income) loss allocated to Parent		789	**(2,780)**	(10,250)
General partner interest in net (income) loss [4]	**(2,394)**	(888)	**(5,684)**	(1,890)
Limited partners interest in net income [4]	**$ 34,415**	$ 30,557	**$ 100,049**	$ 77,098
Net income per common unit basic and diluted	**$ 0.41**	$ 0.44	**$ 1.32**	$ 1.17
Net income per subordinated unit basic and diluted [5]	**$**	$ 0.44	**$ 0.96**	$ 1.17

(1) Financial information for 2010 has been revised to include results attributable to the Bison assets. See *Note 1*.

(2) Cost of product includes product purchases from Anadarko (as defined in *Note 1)* of $20.7 million and $53.5 million for the three and nine months ended September 30, 2011, respectively, and $16.7 million and $49.6 million for the three and nine months ended September 30, 2010, respectively. Operation and maintenance includes charges from Anadarko of $11.6 million and $33.1 million for the three and nine months ended September 30, 2011, respectively, and $8.7 million and $29.3 million for the three and nine months ended September 30, 2010, respectively. General and administrative includes charges from Anadarko of $6.0 million and $16.6 million for the three and nine months ended September 30, 2011, respectively, and $4.1 million and $13.1 million for the three and nine months ended September 30, 2010, respectively. See *Note 4*.

(3) Includes affiliate interest expense of $1.2 million and $4.9 million for the three and nine months ended September 30, 2011, respectively, and $2.9 million and $7.1 million for the three and nine months ended September 30, 2010, respectively. See *Note 7*.

(4) Represents net income for periods including and subsequent to the acquisition of the Partnership assets (as defined in *Note 1*). See also *Note 3*.

(5) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. See *Note 3*.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	**September 30, 2011**	**December 31, 2010** [1]
ASSETS		
Current assets		
Cash and cash equivalents	**$ 251,458**	$ 27,074
Accounts receivable, net [2]	**26,838**	10,890
Other current assets [3]	**6,844**	5,220
Total current assets	**285,140**	43,184
Note receivable Anadarko	**260,000**	260,000
Plant, property and equipment		
Cost	**2,163,882**	1,815,049
Less accumulated depreciation	**430,948**	369,006
Net property, plant and equipment	**1,732,934**	1,446,043
Goodwill and other intangible assets	**117,263**	64,136
Equity investments	**39,614**	40,406
Other assets	**8,592**	2,361
Total assets	**$ 2,443,543**	$ 1,856,130
LIABILITIES, EQUITY AND PARTNERS CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [4]	**$ 17,688**	$ 15,282
Accrued ad valorem taxes	**12,212**	5,986
Income taxes payable	**219**	160
Accrued liabilities [5]	**51,410**	24,436
Total current liabilities	**81,529**	45,864
Long-term debt third parties	**494,061**	299,000
Note payable Anadarko	**175,000**	175,000
Asset retirement obligations and other	**62,860**	61,840
Total long-term liabilities	**731,921**	535,840
Total liabilities	**813,450**	581,704
Equity and partners capital		
Common units (90,140,999 and 51,036,968 units issued and outstanding at September 30, 2011, and December 31, 2010, respectively)	**1,492,186**	810,717
Subordinated units (zero and 26,536,306 units issued and outstanding at September 30, 2011, and December 31, 2010, respectively) [6]		282,384
General partner units (1,839,613 and 1,583,128 units issued and outstanding at September 30, 2011, and December 31, 2010, respectively)	**31,124**	21,505

Parent net investment		69,358
Total partners capital	**1,523,310**	1,183,964
Noncontrolling interests	**106,783**	90,462
Total equity and partners capital	**1,630,093**	1,274,426
Total liabilities, equity and partners capital	**$ 2,443,543**	$ 1,856,130

(1) Financial information for 2010 has been revised to include the financial position and results attributable to the Bison assets. See *Note 1*.

(2) Accounts receivable, net includes amounts receivable from affiliates (as defined in *Note 1)* of $1.2 million and $1.8 million as of September 30, 2011, and December 31, 2010, respectively.

(3) Other current assets includes natural gas imbalance receivables from affiliates (as defined in *Note 1)* of $1.2 million and zero as of September 30, 2011, and December 31, 2010 respectively.

(4) Accounts and natural gas imbalance payables includes amounts payable to affiliates of $1.4 million and $1.5 million as of September 30, 2011, and December 31, 2010, respectively.

(5) Accrued liabilities include amounts payable to affiliates of $0.3 million and $0.6 million as of September 30, 2011, and December 31, 2010, respectively.

(6) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. See *Note 3*.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP

CONSOLIDATED STATEMENT OF EQUITY AND PARTNERS CAPITAL (UNAUDITED)

thousands	Parent Net Investment	Partners Capital: Common Units	Partners Capital: Subordinated Units	Partners Capital: General Partner Units	Noncontrolling Interests	Total
Balance at December 31, 2010 [(1)]	$ 69,358	$ 810,717	$ 282,384	$ 21,505	$ 90,462	$ 1,274,426
Net income	**2,780**	**79,031**	**21,018**	**5,684**	**9,665**	**118,178**
Conversion of subordinated units to common units [(2)]		**272,222**	**(272,222)**			
Issuance of common and general partner units, net of offering expenses		**328,376**		**6,972**		**335,348**
Contributions from noncontrolling interest owners					**16,876**	**16,876**
Distributions to noncontrolling interest owners					**(10,219)**	**(10,219)**
Distributions to unitholders		**(64,232)**	**(31,180)**	**(4,383)**		**(99,795)**
Acquisition of Bison assets	**(92,665)**	**66,313**		**1,352**		**(25,000)**
Net pre-acquisition distributions to Parent	**(1,545)**					**(1,545)**
Elimination of net deferred tax liabilities	**22,072**					**22,072**
Non-cash equity-based compensation and other		**(241)**		**(6)**	**(1)**	**(248)**
Balance at September 30, 2011	**$**	**$ 1,492,186**	**$**	**$ 31,124**	**$ 106,783**	**$ 1,630,093**

(1) Financial information for 2010 has been revised to include the financial position and results attributable to the Bison assets. See *Note 1*.

(2) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. See *Note 3*.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

thousands	Nine Months Ended September 30, 2011	2010 (1)
Cash flows from operating activities		
Net income	**$ 118,178**	$ 97,044
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization and impairments	**65,512**	54,683
Deferred income taxes	**5,180**	1,992
Changes in assets and liabilities:		
Increase in accounts receivable, net	**(17,006)**	(664)
Increase in accounts and natural gas imbalance payables and accrued liabilities, net	**29,642**	11,451
Change in other items, net	**(776)**	(8,797)
Net cash provided by operating activities	**200,730**	155,709
Cash flows from investing activities		
Capital expenditures	**(75,034)**	(105,545)
Acquisitions from affiliates	**(25,000)**	(734,780)
Acquisitions from third parties	**(301,957)**	(18,047)
Investments in equity affiliates	**(93)**	(310)
Proceeds from sale of assets to affiliates	**382**	2,805
Proceeds from sale of assets to third parties		2,425
Net cash used in investing activities	**(401,702)**	(853,452)
Cash flows from financing activities		
Borrowings, net of issuance costs	**1,055,939**	669,987
Repayments of debt	**(869,000)**	(100,000)
Proceeds from issuance of common and general partner units, net of offering expenses	**335,348**	99,279
Distributions to unitholders	**(99,795)**	(67,813)
Contributions from noncontrolling interest owners	**16,876**	2,053
Distributions to noncontrolling interest owners	**(10,219)**	(10,313)
Net contributions from (distributions to) Parent	**(3,793)**	70,966
Net cash provided by financing activities	**425,356**	664,159
Net increase (decrease) in cash and cash equivalents	**224,384**	(33,584)
Cash and cash equivalents at beginning of period	**27,074**	69,984
Cash and cash equivalents at end of period	**$ 251,458**	$ 36,400
Supplemental disclosures		
Elimination of net deferred tax liabilities	**$ 22,072**	$ 214,464
Contribution of assets (to) from Parent	**$ (66)**	$ 7,530

Increase in accrued capital expenditures	**$ 9,641**	$ 13,331
Interest paid	**$ 9,974**	$ 10,278
Interest received	**$ 12,675**	$ 12,675

(1) Financial information for 2010 has been revised to include results attributable to the Bison assets. See *Note 1*.

See accompanying Notes to Consolidated Financial Statements.

WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

Description of business. Western Gas Partners, LP (the Partnership) is a Delaware limited partnership formed in August 2007. As of September 30, 2011, the Partnership s assets included eleven gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline, and interests in Fort Union Gas Gathering, L.L.C. (Fort Union) and White Cliffs Pipeline, L.L.C. (White Cliffs), which are accounted for under the equity method. The Partnership s assets are located in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming), and the Mid-Continent (Kansas and Oklahoma). The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko Petroleum Corporation and its consolidated subsidiaries, as well as third-party producers and customers.

For purposes of these consolidated financial statements, the Partnership refers to Western Gas Partners, LP and its consolidated subsidiaries. The Partnership s general partner is Western Gas Holdings, LLC (the general partner or GP), a wholly owned subsidiary of Anadarko Petroleum Corporation. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union and White Cliffs.

Basis of presentation. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States (GAAP). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership records its 50% proportionate share of the assets, liabilities, revenues and expenses attributable to the Newcastle system. Noncontrolling interests in the Partnership s assets and income represent the aggregate 49% interest in Chipeta Processing LLC (Chipeta) held by Anadarko Petroleum Corporation and a third party.

The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair statement of financial position as of September 30, 2011, and December 31, 2010, results of operations for the three and nine months ended September 30, 2011 and 2010, statement of equity and partners capital for the nine months ended September 30, 2011, and statements of cash flows for the nine months ended September 30, 2011 and 2010. The Partnership s financial results for the three and nine months ended September 30, 2011, are not necessarily indicative of the expected results for the full year ending December 31, 2011.

In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, utilizing historical experience and other methods considered reasonable under the particular circumstances. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates.

Certain information and note disclosures normally included in annual financial statements have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). Accordingly, the accompanying consolidated financial statements and notes should be read in conjunction with the Partnership s 2010 annual report on Form 10-K, as filed with the SEC on February 24, 2011. Management believes that the disclosures made are adequate to make the information not misleading. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

During the three months ended September 30, 2011, $1.3 million of expenses, net, related to prior periods were recorded in the Partnership s consolidated statements of income. As a result of a metering adjustment, $0.7 million of cost of product was recorded during the quarter, of which, $0.3 million related to 2008, $0.2 million related to 2009 and $0.2 million related to 2010. In addition, as a result of a true-up of expenses related to the transition period in conjunction with the Platte Valley acquisition, $0.6 million of cost of product was recorded during the quarter, of which $0.4 million related to the first quarter of 2011 and $0.2 million related to the second quarter of 2011. Management determined the adjustments were not material to the Partnership s consolidated financial statements for the years ended December 31, 2010, 2009 and 2008, nor to the Partnership s interim financial statements, and accordingly, determined that restatement of its previously reported financial statements was not necessary.

WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

Acquisitions. The following table presents the acquisitions completed by the Partnership during 2010 and 2011, and details the funding for those acquisitions through borrowings, cash on hand and/or the issuance of Partnership equity:

thousands except unit and percent amounts	**Acquisition Date**	**Percentage Acquired**	**Borrowings**	**Cash On Hand**	**Common Units Issued**	**GP Units Issued**
Granger [1]	01/29/10	100%	$ 210,000	$ 31,680	620,689	12,667
Wattenberg [2]	08/02/10	100%	450,000	23,100	1,048,196	21,392
White Cliffs [3]	09/28/10	10%		38,047		
Platte Valley [4]	**02/28/11**	**100%**	**303,000**	**602**		
Bison [5]	**07/08/11**	**100%**		**25,000**	**2,950,284**	**60,210**

(1) The assets acquired from Anadarko include (i) the Granger gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of cryogenic trains, a refrigeration train, an NGLs fractionation facility and ancillary equipment. These assets, located in southwestern Wyoming, are referred to collectively as the Granger assets and the acquisition as the Granger acquisition.

(2) The assets acquired from Anadarko include the Wattenberg gathering system and related facilities, including the Fort Lupton processing plant. These assets, located in the Denver-Julesburg Basin, north and east of Denver, Colorado, are referred to collectively as the Wattenberg assets and the acquisition as the Wattenberg acquisition.

(3) White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma, which became operational in June 2009. The Partnership s acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko combined with the acquisition of an additional 9.6% interest in White Cliffs from a third party, are referred to collectively as the White Cliffs acquisition. The Partnership s interest in White Cliffs is referred to as the White Cliffs investment.

(4) The assets acquired from a third party include (i) a natural gas gathering system and related compression and other ancillary equipment, and (ii) cryogenic gas processing facilities. These assets, located in the Denver-Julesburg Basin, are referred to collectively as the Platte Valley assets and the acquisition as the Platte Valley acquisition. See further information below, including the final allocation of the purchase price in August 2011.

(5) The Partnership acquired Anadarko s Bison gas treating facility and related assets located in the Powder River Basin in northeastern Wyoming, including (i) three amine treating units, (ii) compressor units, and (iii) generators. These assets are referred to collectively as the Bison assets and the acquisition as the Bison acquisition. The Bison assets are the only treating and delivery point into the third-party owned Bison pipeline.

Platte Valley acquisition. The Platte Valley acquisition has been accounted for under the acquisition method of accounting. The Platte Valley assets and liabilities were recorded in the consolidated balance sheet at their estimated fair values as of the acquisition date. Results of operations attributable to the Platte Valley assets were included in the Partnership s consolidated statements of income beginning on the acquisition date in the first quarter of 2011.

The following is the final allocation of the purchase price to the assets acquired and liabilities assumed in the Platte Valley acquisition as of September 30, 2011:

thousands	
Property, plant and equipment	**$ 264,521**
Intangible assets	**53,754**
Asset retirement obligations and other liabilities	**(16,318)**

Total purchase price	**$**	**301,957**

WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the Platte Valley acquisition, after consideration of post-closing purchase price adjustments. The fair values of the plant and processing facilities, related equipment, and intangible assets acquired were based on the market, cost and income approaches. The liabilities assumed include certain amounts associated with environmental contingencies estimated by management. All fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. For more information regarding the intangible assets presented in the table above, see *Note 6.*

The following table presents the pro forma condensed financial information as if the Platte Valley acquisition had occurred on January 1, 2011:

thousands except per-unit amount		**Nine Months Ended September 30, 2011**
Revenues	**$**	**500,549**
Net income		**120,904**
Net income attributable to Western Gas Partners, LP		**111,239**
Earnings per common unit basic and diluted	**$**	**1.25**

The pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the acquisition been completed at the assumed date, nor is it necessarily indicative of future operating results of the combined entity. The Partnership s pro forma information in the table above includes $60.2 million of revenues and $40.1 million of operating expenses, excluding depreciation, amortization and impairments, attributable to the Platte Valley assets and is included in the Partnership s consolidated statement of income for the nine months ended September 30, 2011. The pro forma adjustments reflect pre-acquisition results of the Platte Valley assets for January and February 2011, including (a) estimated revenues and expenses; (b) estimated depreciation and amortization based on the purchase price allocated to property, plant and equipment and other intangible assets and estimated useful lives; (c) elimination of $0.7 million of acquisition-related costs; and (d) interest on the Partnership s borrowings under its revolving credit facility to finance the Platte Valley acquisition. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the transactions are properly reflected. The pro forma information does not reflect any cost savings or other synergies anticipated as a result of the acquisition, nor any future acquisition related expenses. Pro forma information is not presented for periods ended on or before December 31, 2010, as it is not practical to determine revenues and cost of product for periods prior to January 1, 2011, the effective date of the gathering and processing agreement with the seller.

Presentation of Partnership acquisitions. References to the Partnership assets refer collectively to the assets owned by the Partnership as of September 30, 2011. Because of Anadarko s control of the Partnership through its ownership of the general partner, each acquisition of Partnership assets as of September 30, 2011, except for the acquisitions of the Platte Valley assets and the 9.6% interest in White Cliffs from third parties, was considered a transfer of net assets between entities under common control. As a result, after each acquisition of assets from Anadarko, the Partnership is required to revise its financial statements to include the activities of the Partnership assets as of the date of common control. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

The Partnership s historical financial statements previously filed with the SEC have been recast in this quarterly report on Form 10-Q to include the results attributable to the Bison assets as if the Partnership owned such assets for all periods presented. The consolidated financial statements for periods prior to the Partnership s acquisition of the Partnership assets have been prepared from Anadarko s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the assets during the periods reported.

WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

Net income attributable to the Partnership assets for periods prior to the Partnership s acquisition of such assets is not allocated to the limited partners for purposes of calculating net income per common unit. In addition, certain amounts in prior periods have been reclassified to conform to the current presentation. The following table presents the impact to the historical consolidated statements of income attributable to the Bison assets:

	Three Months Ended September 30, 2010		
thousands	**Partnership Historical**	**Bison Assets**	**Combined**
Revenues	$ 122,293	$ 758	$ 123,051
Net income (loss)	34,022	(825)	33,197

	Nine Months Ended September 30, 2010		
thousands	**Partnership Historical**	**Bison Assets**	**Combined**
Revenues	$ 376,212	$ 758	$ 376,970
Net income (loss)	98,731	(1,687)	97,044

Equity offerings. The Partnership completed the following public equity offerings during 2010 and 2011:

thousands except unit and per-unit amounts	**Common Units Issued** [(2)]	**GP Units Issued** [(3)]	**Price Per Unit**	**Underwriting Discount and Other Offering Expenses**	**Net Proceeds**
May 2010 equity offering [(1)]	4,558,700	93,035	$ 22.25	$ 4,427	$ 99,074
November 2010 equity offering	8,415,000	171,734	29.92	10,279	246,729
March 2011 equity offering	**3,852,813**	**78,629**	**35.15**	**5,621**	**132,569**
September 2011 equity offering	**5,750,000**	**117,347**	**35.86**	**7,624**	**202,779**

(1) The May 2010 equity offering refers collectively to the May 2010 equity offering issuance, and the June 2010 exercise of the underwriters over-allotment option.

(2) Common units issued includes the issuance of 558,700 common units, 915,000 common units, 302,813 common units and 750,000 common units pursuant to the exercise, in full or in part, of the underwriters over-allotment options granted in connection with the May 2010, November 2010, March 2011 and September 2011 equity offerings, respectively.

(3) GP units issued represents general partner units issued to the general partner in exchange for the general partner s proportionate capital contribution to maintain its 2.0% interest.

Recently issued accounting standards not yet adopted. In May 2011, the Financial Accounting Standards Board (the FASB) issued an Accounting Standards Update (ASU) that further addresses fair-value-measurement accounting and related disclosure requirements. The ASU clarifies the FASB s intent regarding the application of existing fair-value-measurement accounting and disclosure requirements, changes fair-value-measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair-value measurements. The ASU is required to be adopted on a prospective basis beginning January 1, 2012. The Partnership does not expect the adoption of this ASU to have an impact on its consolidated financial statements, other than revised disclosures, where appropriate.

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1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

In September 2011, the FASB issued an ASU that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit s fair value is not required unless, as a result of the qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective prospectively beginning January 1, 2012, with early adoption permitted. Adoption of this ASU will have no impact on the Partnership s consolidated financial statements.

2. PARTNERSHIP DISTRIBUTIONS

The partnership agreement requires the Partnership to distribute all of its available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. The Partnership declared the following cash distributions to its unitholders for the periods presented:

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Cash Distribution	Date of Distribution
March 31, 2010	$ 0.340	$ 22,042	May 2010
June 30, 2010	$ 0.350	$ 24,378	August 2010
September 30, 2010	$ 0.370	$ 26,381	November 2010
March 31, 2011	**$ 0.390**	**$ 33,168**	**May 2011**
June 30, 2011	**$ 0.405**	**$ 36,063**	**August 2011**
September 30, 2011 (1)	**$ 0.420**	**$ 40,323**	**November 2011**

(1) On October 12, 2011, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.42 per unit, or $40.3 million in aggregate, including incentive distributions. The cash distribution is payable on November 10, 2011, to unitholders of record at the close of business on October 31, 2011.

3. NET INCOME PER COMMON UNIT

Common and general partner units. The Partnership s common units are listed on the New York Stock Exchange under the symbol WES. The following table summarizes common, subordinated and general partner units issued or converted during the nine months ended September 30, 2011:

thousands	Common Units	Subordinated Units	General Partner Units	Total
Balance at December 31, 2010	51,037	26,536	1,583	79,156
March 2011 equity offering	**3,853**		**79**	**3,932**
Long-Term Incentive Plan Awards	**14**			**14**
Bison acquisition	**2,951**		**61**	**3,012**
Conversion of subordinated units	**26,536**	**(26,536)**		
September 2011 equity offering	**5,750**		**117**	**5,867**
Balance at September 30, 2011	**90,141**		**1,840**	**91,981**

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3. NET INCOME PER COMMON UNIT (CONTINUED)

Conversion of subordinated units. From its inception through June 30, 2011, the Partnership has paid equal distributions on common, subordinated and general partner units. Upon payment of the cash distribution for the second quarter of 2011, the financial requirements for the conversion of all subordinated units were satisfied. As a result, the 26,536,306 subordinated units were converted on August 15, 2011, on a one-for-one basis, into common units. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. The Partnership s net income was allocated to the general partner and the limited partners, including the holders of the subordinated units, through June 30, 2011, in accordance with their respective ownership percentages. The conversion does not impact the amount of the cash distribution paid or the total number of the Partnership s outstanding units representing limited partner interests.

Anadarko holdings of Partnership equity. As of September 30, 2011, Anadarko held 1,839,613 general partner units representing a 2% general partner interest in the Partnership, 39,789,221 common units representing a 43.3% limited partner interest, and 100% of the Partnership s incentive distribution rights, or IDRs. The public held 50,351,778 common units, representing a 54.7% interest in the Partnership.

The Partnership s net income for periods including and subsequent to the Partnership s acquisitions of the Bison assets in 2011, and the White Cliffs investment and Wattenberg assets in 2010, is allocated to the general partner and the limited partners in accordance with their respective ownership percentages, and, when applicable, giving effect to incentive distributions allocable to the general partner. The Partnership s net income allocable to the limited partners is allocated between the common and subordinated unitholders by applying the provisions of the partnership agreement that govern actual cash distributions as if all earnings for the period had been distributed. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner, common unitholders and subordinated unitholders consistent with actual cash distributions, including incentive distributions allocable to the general partner. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner, common unitholders and subordinated unitholders in accordance with their respective ownership percentages during each period.

Basic and diluted net income per common unit is calculated by dividing the limited partners interest in net income by the weighted average number of common units outstanding during the period. The common units issued in connection with acquisitions and equity offerings during 2010 and 2011 are included on a weighted-average basis for periods they were outstanding.

The following table illustrates the Partnership s calculation of net income per unit for common and subordinated units:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands except per-unit amounts	**2011**	**2010**	**2011**	**2010**
Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238
Pre-acquisition net (income) loss allocated to Parent		789	**(2,780)**	(10,250)
General partner interest in net (income) loss	**(2,394)**	(888)	**(5,684)**	(1,890)
Limited partners interest in net income	**$ 34,415**	$ 30,557	**$ 100,049**	$ 77,098
Net income allocable to common units	**$ 34,415**	$ 18,770	**$ 79,030**	$ 46,150

Net income allocable to subordinated units				11,787		**21,019**		30,948
Limited partners interest in net income	**$**	**34,415**	$	30,557	**$**	**100,049**	$	77,098
Net income per unit basic and diluted								
Common units	**$**	**0.41**	$	0.44	**$**	**1.32**	$	1.17
Subordinated units	**$**		$	0.44	**$**	**0.96**	$	1.17
Weighted average units outstanding basic and diluted								
Common units		**84,667**		42,257		**59,647**		39,412
Subordinated units				26,536		**21,968**		26,536

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4. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from services provided to Anadarko as well as from the sale of residue gas, condensate and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operating and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership s general and administrative expenses are paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the omnibus agreement. Affiliate expenses do not inherently bear a direct relationship to affiliate revenues and third-party expenses do not necessarily bear a direct relationship to third-party revenues. See *Note 1* for further information related to contributions of assets to the Partnership by Anadarko.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries, held in separate bank accounts, is generally swept to centralized accounts. Prior to the Partnership s acquisitions of the Bison assets in 2011, and the White Cliffs investment and Wattenberg assets in 2010, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. Anadarko charged or credited the Partnership interest at a variable rate on outstanding affiliate balances for the periods these balances remained outstanding. The outstanding affiliate balances were entirely settled through an adjustment to parent net investment in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of the Partnership assets, the Partnership cash-settles transactions related to such assets directly with third parties and with Anadarko affiliates and affiliate-based interest expense on current intercompany balances is not charged.

Note receivable from Anadarko. Concurrent with the closing of the Partnership s May 2008 initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%. Interest on the note is payable quarterly. The fair value of the note receivable from Anadarko was approximately $274.2 million and $258.9 million at September 30, 2011, and December 31, 2010, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments.

Commodity price swap agreements. The Partnership holds commodity price swap agreements with Anadarko to mitigate exposure to commodity price volatility that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs. Notional volumes for each of the swap agreements are not specifically defined; instead, the commodity price swap agreements apply to the actual volume of natural gas, condensate and NGLs purchased and sold at the Hilight, Hugoton, Newcastle, Granger and Wattenberg assets. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be measured at fair value. The Partnership reports its realized gains and losses on the commodity price swap agreements related to sales in natural gas, natural gas liquids and condensate sales in its consolidated statements of income in the period in which the associated revenues are recognized. The Partnership reports its realized gains and losses on the commodity price swap agreements related to purchases in cost of product in its consolidated statements of income in the period in which the associated purchases are recorded. The Partnership has not entered into any new commodity price swap agreements since the fourth quarter of 2010.

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4. TRANSACTIONS WITH AFFILIATES (CONTINUED)

The following table summarizes realized gains and losses on commodity price swap agreements:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2011**	**2010**	**2011**	**2010**
Gains (losses) on commodity price swap agreements:				
Natural gas sales	**$ 8,280**	$ 7,338	**$ 24,079**	$ 12,803
Natural gas liquids sales	**(9,218)**	5,145	**(25,736)**	5,840
Total	**(938)**	12,483	**(1,657)**	18,643
Losses on commodity price swap agreements related to purchases	**(6,501)**	(9,627)	**(19,377)**	(16,038)
Net gains (losses) on commodity price swap agreements	**$ (7,439)**	$ 2,856	**$ (21,034)**	$ 2,605

Gas gathering and processing agreements. The Partnership has significant gas gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. Approximately 80% and 73% of the Partnership s gathering, transportation and treating throughput for the three months ended September 30, 2011 and 2010, respectively, and 78% for both the nine months ended September 30, 2011 and 2010, was attributable to natural gas production owned or controlled by Anadarko. Approximately 69% and 73% of the Partnership s processing throughput for the three months ended September 30, 2011 and 2010, respectively, and 71% and 76% for the nine months ended September 30, 2011 and 2010, respectively, was attributable to natural gas production owned or controlled by Anadarko.

Summary of affiliate transactions. Affiliate transactions include revenue from affiliates, reimbursement of operating expenses and purchases of natural gas. The following table summarizes affiliate transactions, including transactions with the general partner:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2011**	**2010**	**2011**	**2010**
Revenues (1)	**$ 137,481**	$ 107,849	**$ 370,700**	$ 320,903
Cost of product (1)	**20,723**	16,729	**53,519**	49,554
Operation and maintenance (2)	**11,643**	8,740	**33,137**	29,271
General and administrative (3)	**6,004**	4,081	**16,620**	13,085
Operating expenses	**38,370**	29,550	**103,276**	91,910
Interest income (4)	**4,225**	4,225	**12,675**	12,675
Interest expense (5)	**1,235**	2,936	**4,915**	7,119
Distributions to unitholders (6)	**18,000**	13,067	**48,864**	37,915
Contributions from noncontrolling interest owners	**4,647**		**8,266**	2,019
Distributions to noncontrolling interest owners	**1,335**	1,925	**5,882**	5,051

(1) Represents amounts recognized under gathering, treating or processing agreements, and purchase and sale agreements with affiliates of Anadarko.

(2) Represents expenses incurred under the services and secondment agreement with Anadarko, as applicable. See *Note 1*.

(3) Represents general and administrative expense incurred under the omnibus agreement with Anadarko, as applicable. See *Note 1*.

(4) Represents interest income recognized on the note receivable from Anadarko.

(5) Represents interest expense recognized on the note payable to Anadarko. This line item also includes interest expense, net on affiliate balances related to the Bison assets, White Cliffs investment and Wattenberg assets for periods prior to the acquisition of such assets. See *Note 7*.

(6) Represents distributions paid to an affiliate of Anadarko under the partnership agreement.

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4. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Concentration of credit risk. Anadarko was the only customer from whom revenues exceeded 10% of the Partnership s consolidated revenues for all periods presented on the Partnership s consolidated statements of income.

5. PROPERTY, PLANT AND EQUIPMENT

A summary of the historical cost of the Partnership s property, plant and equipment is as follows:

thousands	**September 30, 2011**	**December 31, 2010**
Land	**$ 354**	$ 354
Gathering systems	**2,005,403**	1,706,717
Pipelines and equipment	**84,248**	83,613
Assets under construction	**70,204**	21,662
Other	**3,673**	2,703
Total property, plant and equipment	**2,163,882**	1,815,049
Accumulated depreciation	**430,948**	369,006
Net property, plant and equipment	**$ 1,732,934**	$ 1,446,043

The cost of property classified as Assets under construction is excluded from capitalized costs being depreciated. These amounts represent property that is not yet suitable to be placed into productive service as of the respective balance sheet date. In addition, property, plant and equipment cost as well as third-party accrued liability balances in the Partnership s consolidated balance sheets include $19.0 million and $9.3 million of accrued capital as of September 30, 2011, and December 31, 2010, respectively, representing estimated capital expenditures for which invoices had not yet been processed.

6. OTHER INTANGIBLE ASSETS

The intangible asset balance in the Partnership s consolidated balance sheets represents the estimated economic value related to the contracts assumed by the Partnership in connection with the Platte Valley acquisition in February 2011, that dedicate certain customers field production to the acquired gathering and processing system. These long-term contracts provide an extended commercial relationship with the existing customers whereby the Partnership will have the opportunity to gather and process additional production from the customers acreage. These contracts are generally limited, however, by the quantity and production life of the underlying natural gas resource base.

At September 30, 2011, the carrying value of the Partnership s customer relationship intangible assets was $53.2 million, net of $0.6 million of accumulated amortization, and is included in goodwill and other intangible assets in the Partnership s consolidated balance sheets. Customer relationships are amortized on a straight-line basis over 50 years, which is the estimated productive life of the reserves covered by the underlying acreage ultimately expected to be produced and gathered or processed through the Partnership s assets subject to current contractual arrangements.

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6. OTHER INTANGIBLE ASSETS (CONTINUED)

Estimated future amortization for these intangible assets is as follows:

thousands	Future amortization
October December 2011	$ 269
2012	1,075
2013	1,075
2014	1,075
2015	1,075

The Partnership assesses intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Impairments exist when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset s carrying amount over its estimated fair value such that the asset s carrying amount is adjusted to its estimated fair value with an offsetting charge to operating expense. No intangible asset impairment has been recognized in connection with these assets.

7. DEBT AND INTEREST EXPENSE

The following table presents the Partnership s outstanding debt as of September 30, 2011, and December 31, 2010:

	September 30, 2011			**December 31, 2010**		
thousands	**Principal**	**Carrying Value**	**Fair Value**	**Principal**	**Carrying Value**	**Fair Value**
Revolving credit facility	**$**	**$**	**$**	$ 49,000	$ 49,000	$ 49,000
5.375% Senior Notes due 2021	**500,000**	**494,061**	**502,993**			
Wattenberg term loan				250,000	250,000	250,000
Note payable to Anadarko	**175,000**	**175,000**	**176,246**	175,000	175,000	168,116
Total debt outstanding (1)	**$ 675,000**	**$ 669,061**	**$ 679,239**	$ 474,000	$ 474,000	$ 467,116

(1) The Partnership s consolidated balance sheets include accrued interest expense of $10.0 million and $0.8 million as of September 30, 2011, and December 31, 2010, respectively, which is included in accrued liabilities.

Fair value of debt. The fair value of debt reflects any premium or discount for the difference between the stated interest rate and quarter-end market interest rate and is based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

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7. DEBT AND INTEREST EXPENSE (CONTINUED)

Debt activity. The following table presents the debt activity of the Partnership for the nine months ended September 30, 2011:

thousands	**Carrying Value**
Balance as of December 31, 2010	$ 474,000
First Quarter 2011	
Revolving credit facility borrowings	560,000
Repayment of revolving credit facility	(139,000)
Repayment of Wattenberg term loan	(250,000)
Revolving credit facility borrowings Swingline	10,000
Repayment of revolving credit facility Swingline	(10,000)
Second Quarter 2011	
Revolving credit facility borrowings Swingline	10,000
Issuance of 5.375% Senior Notes due 2021	500,000
Repayment of revolving credit facility	(470,000)
Repayment of revolving credit facility Swingline	(10,000)
Other and changes in debt discount	(6,054)
Third Quarter 2011	
Revolving credit facility borrowings Swingline	**10,000**
Revolving credit facility borrowings	**10,000**
Repayment of revolving credit facility Swingline	**(10,000)**
Repayment of revolving credit facility	**(10,000)**
Other and changes in debt discount	**115**
Balance as of September 30, 2011	**$ 669,061**

5.375% Senior Notes due 2021. In May 2011, the Partnership completed the offering of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the Notes) at a price to the public of 98.778% of the face amount of the Notes. Interest on the Notes will be paid semi-annually on June 1 and December 1 of each year, commencing on December 1, 2011. The Notes mature on June 1, 2021, unless redeemed, in whole or in part, at any time prior to maturity, at a redemption price that includes a make-whole premium. Proceeds from the offering of the Notes (net of the underwriting discount of $3.3 million and debt issuance costs) were used to repay the then-outstanding balance on the Partnership s revolving credit facility, with the remainder used for general partnership purposes.

The Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of the Partnership s wholly owned subsidiaries (the Subsidiary Guarantors). The Subsidiary Guarantors guarantees will be released if, among other things, the Subsidiary Guarantors are released from their obligations under the Partnership s revolving credit facility. See *Note 9* for the financial statements of the Subsidiary Guarantors.

The Notes indenture contains customary events of default including, among others, (i) default in any payment of interest on any debt securities when due that continues for 30 days; (ii) default in payment, when due, of principal of or premium, if any, on the Notes at maturity; and (iii) certain events of bankruptcy or insolvency with respect to the Partnership. The indenture governing the Notes also contains covenants that limit, among other things, the ability of the Partnership and the Subsidiary Guarantors to (i) create liens on their principal properties; (ii) engage in sale and leaseback transactions; and (iii) merge or consolidate with another entity or sell, lease or transfer substantially all of their properties or assets to another entity. At September 30, 2011, the Partnership was in compliance with all covenants under the Notes.

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7. DEBT AND INTEREST EXPENSE (CONTINUED)

Note payable to Anadarko. In December 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko. The interest rate was fixed at 4.00% until November 2010. The term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity in 2013. The Partnership has the option, at any time, to repay the outstanding principal amount in whole or in part.

The provisions of the five-year term loan agreement contain customary events of default, including (i) non-payment of principal when due or non-payment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership and (iii) a change of control. At September 30, 2011, the Partnership was in compliance with all covenants under this agreement.

Revolving credit facility. In March 2011, the Partnership entered into an amended and restated $800.0 million senior unsecured revolving credit facility (the RCF) and borrowed $250.0 million under the RCF to repay the Wattenberg term loan (described below). The RCF amended and restated the Partnership s $450.0 million credit facility. The RCF matures in March 2016 and bears interest at London Interbank Offered Rate, or LIBOR, plus applicable margins currently ranging from 1.30% to 1.90%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, and (c) LIBOR plus 1%, plus applicable margins currently ranging from 0.30% to 0.90%. The interest rate was 1.74% and 3.26% at September 30, 2011, and at December 31, 2010, respectively. The Partnership is required to pay a quarterly facility fee currently ranging from 0.20% to 0.35% of the commitment amount (whether used or unused), based upon the Partnership s senior unsecured debt rating. The facility fee rate was 0.25% and 0.50% at September 30, 2011, and December 31, 2010, respectively.

The RCF contains covenants that limit, among other things, the ability of the Partnership and certain of its subsidiaries to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of its business, sell all or substantially all of the Partnership s assets, make certain transfers, enter into certain affiliate transactions, make distributions or other payments other than distributions of available cash under certain conditions and use proceeds other than for partnership purposes. The RCF also contains various customary covenants, customary events of default and certain financial tests as of the end of each quarter, including a maximum consolidated leverage ratio (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to consolidated EBITDA for the most recent four consecutive fiscal quarters ending on such day) of 5.0 to 1.0, or a consolidated leverage ratio of 5.5 to 1.0 with respect to quarters ending in the 270-day period immediately following certain acquisitions, and a minimum consolidated interest coverage ratio (which is defined as the ratio of consolidated EBITDA for the most recent four consecutive fiscal quarters to consolidated interest expense for such period) of 2.0 to 1.0.

All amounts due under the RCF are unconditionally guaranteed by the Partnership s wholly owned subsidiaries. The Partnership will no longer be required to comply with the minimum consolidated interest coverage ratio as well as the subsidiary guarantees and certain of the aforementioned covenants, if the Partnership obtains two of the following three ratings: BBB- or better by S&P, Baa3 or better by Moody s, or BBB- or better by Fitch. As of September 30, 2011, no amounts were outstanding under the RCF, and $800.0 million was available for borrowing. At September 30, 2011, the Partnership was in compliance with all covenants under the RCF.

Wattenberg term loan. In connection with the Wattenberg acquisition, in August 2010 the Partnership borrowed $250.0 million under a three-year term loan from a group of banks (Wattenberg term loan). The Wattenberg term loan incurred interest at LIBOR plus a margin ranging from 2.50% to 3.50% depending on the Partnership s consolidated leverage ratio as defined in the Wattenberg term loan agreement. The Partnership repaid the Wattenberg term loan in March 2011 using borrowings from its RCF and recognized $1.3 million of accelerated amortization expense related to its early repayment.

Interest-rate swap agreement. The Partnership entered into a forward-starting interest-rate swap agreement in March 2011 to mitigate the risk of rising interest rates prior to the issuance of the Notes. In May 2011, the Partnership issued the Notes and terminated the swap agreement, realizing a loss of $1.9 million, which is included in other expense, net in the Partnership s consolidated statements of income.

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7. DEBT AND INTEREST EXPENSE (CONTINUED)

Interest expense. The following table summarizes the amounts included in interest expense:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2011**	2010	**2011**	2010
Third Parties				
Interest expense on long-term debt	**$ 6,739**	$ 3,012	**$ 13,889**	$ 5,119
Amortization of debt issuance costs and commitment fees	**1,078**	860	**4,282**	2,309
Capitalized interest	**(121)**		**(134)**	
Total interest expense third parties	**7,696**	3,872	**18,037**	7,428
Affiliates				
Interest expense on notes payable to Anadarko	**1,234**	1,750	**3,701**	5,250
Interest expense, net on affiliate balances [(1)]	**1**	1,160	**1,214**	1,773
Credit facility commitment fees		26		96
Total interest expense affiliates	**1,235**	2,936	**4,915**	7,119
Interest expense	**$ 8,931**	$ 6,808	**$ 22,952**	$ 14,547

(1) Incurred on intercompany borrowings associated with the Bison assets in 2011, and associated with the Bison assets, White Cliffs investment and Wattenberg assets in 2010, prior to such assets being acquired by the Partnership.

8. COMMITMENTS AND CONTINGENCIES

Litigation and legal proceedings. In March 2011, DCP Midstream LP (DCP) filed a lawsuit against Anadarko and others, including a Partnership subsidiary, Kerr-McGee Gathering LLC, in Weld County District Court (the Court) in Colorado, alleging that Anadarko and its affiliates diverted gas from DCP s gathering and processing facilities in breach of certain dedication agreements. In addition to various claims against Anadarko, DCP is claiming unjust enrichment and other damages against Kerr-McGee Gathering LLC, the entity which holds the Wattenberg assets. In July 2011, the Court denied the defendants motion to dismiss without ruling on the merits and the case is proceeding to the discovery phase. Management does not believe the outcome of this proceeding will have a material effect on the Partnership s financial condition, results of operations or cash flows. The Partnership intends to vigorously defend this litigation. Furthermore, without regard to the merit of DCP s claims, management believes that the Partnership has adequate contractual indemnities covering the claims against it in this lawsuit.

In addition, from time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership s financial condition, results of operations or cash flows.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

8. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting the Partnership s operations. The leases for the shared field offices extend through 2018, and the lease for the warehouse extends through March 2012 and includes an early termination clause. The lease for the Partnership s corporate offices expires in January 2012, and during the three months ended September 30, 2011, Anadarko entered into a new agreement for the Partnership s corporate offices that extends through March 2017.

In addition, during 2010, Anadarko and Kerr-McGee Gathering LLC purchased previously leased compression equipment used at the Granger and Wattenberg assets, which terminated the leases and associated lease expense. The purchased compression equipment was contributed to the Partnership pursuant to provisions of the contribution agreements for the Granger and the Wattenberg acquisitions.

As of September 30, 2011, there was no material change in the existing contractual lease obligations for the shared field offices and warehouse leases from December 31, 2010. Rent expense associated with these leases and the previously leased compression equipment was approximately \$0.6 million and \$1.7 million for the three and nine months ended September 30, 2011, respectively, and \$0.5 million and \$5.4 million for the three and nine months ended September 30, 2010, respectively.

9. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS

The Partnership may issue an indeterminate amount of common units and various debt securities under its effective shelf registration statement on file with the SEC. The Notes are, and any future debt securities issued under such registration statement may be, guaranteed by the Subsidiary Guarantors. The guarantees are full, unconditional, joint and several. The following condensed consolidating financial information reflects the Partnership s stand-alone accounts, the combined accounts of the Subsidiary Guarantors, the accounts of the Non-Guarantor Subsidiary, consolidating adjustments, and eliminations and the Partnership s consolidated financial information. The condensed consolidating financial information should be read in conjunction with the Partnership s accompanying consolidated financial statements and related notes.

Western Gas Partners, LP s and the Subsidiary Guarantors investment in and equity income from their consolidated subsidiaries are presented in accordance with the equity method of accounting in which the equity income from consolidated subsidiaries includes the results of operations of the Partnership assets for periods including and subsequent to the Partnership s acquisition of the Partnership assets.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

9. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS (CONTINUED)

	Statement of Income Three Months Ended September 30, 2011				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

	Statement of Income Three Months Ended September 30, 2010				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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9. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS (CONTINUED)

	Statement of Income Nine Months Ended September 30, 2011				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

	Statement of Income Nine Months Ended September 30, 2010				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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9. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS (CONTINUED)

	Balance Sheet September 30, 2011				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

	Balance Sheet December 31, 2010				
thousands	Western Gas Partners, LP	Subsidiary Guarantors	Non-Guarantor Subsidiary	Eliminations	Consolidated

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

9. CONDENSED CONSOLIDATING FINANCIAL STATEMENTS (CONTINUED)

	Statement of Cash Flows Nine Months Ended September 30, 2011				
thousands	**Western Gas Partners, LP**	**Subsidiary Guarantors**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
Net income	**$ 105,732**	**$ 161,074**	**$ 19,725**	**$ (168,353)**	**$ 118,178**
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity income from consolidated subsidiaries	**(158,293)**	**(10,060)**		**168,353**	
Depreciation, amortization and impairments	**41**	**61,120**	**4,351**		**65,512**
Change in other items, net	**(134,596)**	**151,714**	**(78)**		**17,040**
Net cash provided by (used in) operating activities	**(187,116)**	**363,848**	**23,998**		**200,730**
Net cash used in investing activities	**(25,000)**	**(368,866)**	**(25,400)**	**17,564**	**(401,702)**
Net cash provided by (used in) financing activities	**422,529**	**5,018**	**15,373**	**(17,564)**	**425,356**
Net increase (decrease) in cash and cash equivalents	**210,413**		**13,971**		**224,384**
Cash and cash equivalents at beginning of period	**21,480**		**5,594**		**27,074**
Cash and cash equivalents at end of period	**$ 231,893**	**$**	**$ 19,565**	**$**	**$ 251,458**

	Statement of Cash Flows Nine Months Ended September 30, 2010				
thousands	**Western Gas Partners, LP**	**Subsidiary Guarantors**	**Non-Guarantor Subsidiary**	**Eliminations**	**Consolidated**
Net income	$ 78,775	$ 103,152	$ 15,930	$ (100,813)	$ 97,044
Adjustments to reconcile net income to net cash provided by operating activities:					
Equity income from consolidated subsidiaries	(92,688)	(8,125)		100,813	

Depreciation, amortization and impairments	40	50,333	4,310		54,683
Change in other items, net	95,556	(90,098)	(1,476)		3,982
Net cash provided by operating activities	81,683	55,262	18,764		155,709
Net cash used in investing activities	(734,781)	(116,624)	(2,047)		(853,452)
Net cash provided by (used in) financing activities	621,720	61,362	(18,923)		664,159
Net increase (decrease) in cash and cash equivalents	(31,378)		(2,206)		(33,584)
Cash and cash equivalents at beginning of period	61,630		8,354		69,984
Cash and cash equivalents at end of period	$ 30,252	$	$ 6,148	$	$ 36,400

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

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included under Part I, Item 1 of this quarterly report, as well as our historical consolidated financial statements, and the notes thereto, which are included in Part I, Item 8 of our 2010 annual report on Form 10-K as filed with the Securities and Exchange Commission, or SEC, on February 24, 2011. Unless the context otherwise requires, references to we, us, our, the Partnership or Western Gas Partners refers to Western Gas Partners, LP a subsidiaries, including the financial results of the Partnership assets (described below) from their respective acquisition dates, combined with the financial results and operations of the Wattenberg assets (defined in Acquisitions) and 0.4% interest in White Cliffs (defined below) for all periods presented. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions as being our historical financial results. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner. Our general partner refers to Western Gas Holdings, LLC, a wholly owned subsidiary of Anadarko and the general partner of the Partnership. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union Gas Gathering, L.L.C., or Fort Union, and White Cliffs Pipeline, L.L.C., or White Cliffs. References to the Partnership assets refer collectively to the assets owned by the Partnership as of September 30, 2011.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions by Partnership management, forward-looking statements concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including may, will, believe, expect, anticipate, estimate, continue, or other similar words. These staten future expectations, contain projections of results of operations or financial condition or include other forward-looking information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct.

These forward-looking statements involve risks and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- *our assumptions about the energy market;*
- *future throughput, including Anadarko s production, which is gathered or processed by or transported through our assets;*
- *operating results;*
- *competitive conditions;*
- *technology;*
- *the availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;*
- *the supply of and demand for, and the prices of, oil, natural gas, NGLs and other products or services;*
- *the weather;*
- *inflation;*
- *the availability of goods and services;*
- *general economic conditions, either internationally, nationally or within the jurisdictions in which we are doing business;*

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changes in environmental and safety regulations; environmental risks; regulations by the Federal Energy Regulatory Commission, or FERC; and liability under federal and state laws and regulations;

legislative or regulatory changes affecting our status as a partnership for federal income tax purposes;

changes in the financial or operational condition of our sponsor, Anadarko, including changes as a result of remaining claims related to the Deepwater Horizon events for which Anadarko is not indemnified;

changes in Anadarko s capital program, strategy or desired areas of focus;

our commitments to capital projects;

the ability to utilize our revolving credit facility;

the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;

our ability to repay debt;

our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;

our ability to acquire assets on acceptable terms;

non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko;

electronic, cyber and physical security breaches; and

other factors discussed below and elsewhere in Risk Factors under Part I, Item 1A in our 2010 annual report on Form 10-K, and in Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates under Part II, Item 7 included in our 2010 annual report on Form 10-K, our quarterly reports on Form 10-Q and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this report could cause our actual results to differ materially from those contained in any forward-looking statement. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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EXECUTIVE SUMMARY

We are a growth-oriented limited partnership organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently operate in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma) and are engaged primarily in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko and third-party producers and customers. As of September 30, 2011, our assets consist of eleven gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline, and interests in a gas gathering system and a crude oil pipeline accounted for under the equity method.

Significant financial highlights during the first nine months of 2011 include the following:

In September 2011, we issued 5,750,000 common units to the public, generating net proceeds of $202.8 million, including the general partner s proportionate capital contributions to maintain its 2.0% general partner interest. Net proceeds from this offering will be used for general partnership purposes and to repay amounts outstanding under our revolving credit facility.

Our stable operating cash flow enabled us to raise our distribution to $0.42 per unit for the third quarter of 2011, representing a 4% increase over the distribution for the second quarter of 2011 and our tenth consecutive quarterly increase.

In July 2011, we acquired Anadarko s Bison gas treating facility and related assets located in the Powder River Basin in northeastern Wyoming. The consideration paid consisted of $25.0 million in cash on hand and the issuance of common units and general partner units as described in *Acquisitions*.

In May 2011, we issued $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021. Net proceeds from this issuance were used primarily to repay amounts outstanding under our revolving credit facility. Refer to *Liquidity and Capital Resources* for additional information.

In March 2011, we issued 3,852,813 common units to the public, generating net proceeds of $132.6 million, including the general partner s proportionate capital contributions to maintain its 2.0% general partner interest. Net proceeds from this offering were used primarily to repay amounts outstanding under our revolving credit facility.

In March 2011, we entered into an amended and restated $800.0 million senior unsecured revolving credit facility to amend and restate our $450.0 million credit facility. Refer to *Liquidity and Capital Resources* for additional information.

In February 2011, we acquired the Platte Valley gathering system and processing plant from a third party for $302.0 million, funded primarily by borrowings under our revolving credit facility. These assets are located in the Denver-Julesburg basin, north and east of Denver, Colorado, and consist of a cryogenic processing plant, two fractionation trains and a natural gas gathering system.

Significant operational highlights during the first nine months of 2011 include the following:

Our gross margin (total revenues less cost of product) for the three months ended September 30, 2011, averaged $0.56 per Mcf, representing a 12% increase compared to the three months ended September 30, 2010, and averaged $0.55 per Mcf for the nine months ended September 30, 2011, representing an 2% increase compared to the nine months ended September 30, 2010. The increase in gross margin per Mcf is primarily due to volume growth related to higher-margin systems, including the addition of the Platte Valley system, and increased throughput at the Wattenberg and Hilight systems. The predominantly fee-based and fixed-price structure of our contracts mitigated the impact of changes in commodity prices on our gross margin.

Our throughput totaled 1,957 MMcf/d and 1,942 MMcf/d for the three and nine months ended September 30, 2011, respectively, representing an 11% and 16% increase, respectively, compared to the same periods in 2010.

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ACQUISITIONS

Acquisitions. The following table presents our acquisitions completed during 2010 and 2011, and details the funding for those acquisitions through borrowings, cash on hand and/or the issuance of equity:

thousands except unit and percent amounts	**Acquisition Date**	**Percentage Acquired**	**Borrowings**	**Cash On Hand**	**Common Units Issued**	**GP Units Issued**
Granger [1]	01/29/10	100%	$ 210,000	$ 31,680	620,689	12,667
Wattenberg [2]	08/02/10	100%	450,000	23,100	1,048,196	21,392
White Cliffs [3]	09/28/10	10%		38,047		
Platte Valley [4]	**02/28/11**	**100%**	**303,000**	**602**		
Bison [5]	**07/08/11**	**100%**		**25,000**	**2,950,284**	**60,210**

(1) The assets acquired from Anadarko include (i) the Granger gathering system, a 750-mile gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of two cryogenic trains with combined capacity of 200 MMcf/d, a refrigeration train with capacity of 100 MMcf/d, an NGLs fractionation facility with capacity of 9,500 barrels per day, and ancillary equipment. These assets, located in southwestern Wyoming, are referred to collectively as the Granger assets or Granger system and the acquisition as the Granger acquisition. In connection with the acquisition, we entered into a ten-year fee-based arrangement covering a majority of the Granger assets affiliate throughput and five-year, fixed-price commodity swap agreements with Anadarko, which cover non-fee-based volumes processed at the Granger complex.

(2) The assets acquired from Anadarko include the Wattenberg gathering system and related facilities, including the Fort Lupton processing plant. These assets, located in the Denver-Julesburg Basin, north and east of Denver, Colorado, are referred to collectively as the Wattenberg assets or Wattenberg system and the acquisition as the Wattenberg acquisition. In connection with the acquisition, we entered into a ten-year fee-based arrangement covering all of the Wattenberg assets affiliate throughput and five-year, fixed-price commodity swap agreements with Anadarko, which fix the margin we will realize from the purchase and sale of natural gas, condensate or NGLs at the Wattenberg assets.

(3) White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma, which became operational in June 2009. Our acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko combined with the acquisition of an additional 9.6% interest in White Cliffs from a third party, are referred to collectively as the White Cliffs acquisition. Our interest in White Cliffs is referred to as the White Cliffs investment.

(4) The assets acquired from a third party include (i) a processing plant with cryogenic capacity of 84 MMcf/d, (ii) two fractionation trains, (iii) a 1,098 mile natural gas gathering system that delivers gas to the Platte Valley plant, either directly or through our Wattenberg gathering system, and (iv) related equipment. These assets, located in the Denver-Julesburg Basin, are referred to collectively as the Platte Valley assets or Platte Valley system and the acquisition as the Platte Valley acquisition. In connection with the acquisition, we entered into long-term fee-based agreements with the seller to gather and process its existing gas production, as well as to expand the existing gathering systems and processing capacity. We financed the Platte Valley acquisition with borrowings under our revolving credit facility. See *Note 1. Description of Business and Basis of Presentation* in the *Notes to Consolidated Financial Statements* included under Part I, Item 1 of this Form 10-Q.

(5) We acquired Anadarko s Bison gas treating facility and related assets located in the Powder River Basin in northeastern Wyoming, including (i) three amine treating units with a combined CO_2 treating capacity of 450 MMcf/d, (ii) three compressor units with combined compression of 5,230 horsepower, and (iii) five generators with combined power output of 6.5 megawatts. These assets are referred to collectively as the Bison assets and the acquisition as the Bison acquisition. The Bison assets are the only treating and delivery point into the third-party owned Bison pipeline.

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Presentation of Partnership acquisitions. References to the Partnership assets refer collectively to the assets owned by the Partnership as of September 30, 2011. Because of Anadarko s control of the Partnership through its ownership of our general partner, each acquisition of Partnership assets as of September 30, 2011, except for the acquisitions of the Platte Valley assets and the 9.6% interest in White Cliffs from third parties, was considered a transfer of net assets between entities under common control. As a result, after each acquisition of assets from Anadarko, the Partnership is required to revise our financial statements to include the activities of the Partnership assets as of the date of common control. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

Our historical financial statements as filed with the SEC have been recast in this quarterly report on Form 10-Q to include the results attributable to the Bison assets as if we owned such assets for all periods presented. The consolidated financial statements for periods prior to our acquisition of the Partnership assets have been prepared from Anadarko s historical cost basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the assets during the periods reported. Net income attributable to the Partnership assets for periods prior to the Partnership s acquisition of the Bison assets in 2011, and the White Cliffs investment and Wattenberg assets in 2010, is not allocated to the limited partners for purposes of calculating net income per common unit. In addition, certain amounts in prior periods have been reclassified to conform to the current presentation. Our noncontrolling interests represent the aggregate 49% interest in Chipeta Processing LLC (Chipeta) held by Anadarko and a third party.

EQUITY OFFERINGS

Equity offerings. We completed the following public equity offerings during 2010 and 2011:

thousands except unit and per-unit amounts	**Common Units Issued** [2]	**GP Units Issued** [3]	**Price Per Unit**	**Underwriting Discount and Other Offering Expenses**	**Net Proceeds**
May 2010 equity offering [1]	4,558,700	93,035	$ 22.25	$ 4,427	$ 99,074
November 2010 equity offering	8,415,000	171,734	29.92	10,279	246,729
March 2011 equity offering	**3,852,813**	**78,629**	**35.15**	**5,621**	**132,569**
September 2011 equity offering	**5,750,000**	**117,347**	**35.86**	**7,624**	**202,779**

(1) The May 2010 equity offering refers collectively to the May 2010 equity offering issuance, and the June 2010 exercise of the underwriters over-allotment option.

(2) Common units issued includes the issuance of 558,700 common units, 915,000 common units, 302,813 common units and 750,000 common units pursuant to the exercise, in full or in part, of the underwriters over-allotment options granted in connection with the May 2010, November 2010, March 2011 and September 2011 equity offerings, respectively.

(3) GP units issued represents general partner units issued to the general partner in exchange for the general partner s proportionate capital contribution to maintain its 2.0% interest.

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RESULTS OF OPERATIONS
OPERATING RESULTS

The following tables and discussion present a summary of our results of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2011**	**2010**	**2011**	**2010**
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 71,873**	$ 60,363	**$ 211,418**	$ 172,769
Natural gas, natural gas liquids and condensate sales	**101,079**	59,887	**263,041**	196,792
Equity income and other, net	**2,911**	2,801	**10,051**	7,409
Total revenues (1)	**175,863**	123,051	**484,510**	376,970
Total operating expenses (1)	**130,391**	86,272	**352,426**	265,882
Operating income	**45,472**	36,779	**132,084**	111,088
Interest income affiliates	**4,225**	4,225	**12,675**	12,675
Interest expense	**(8,931)**	(6,808)	**(22,952)**	(14,547)
Other income (expense), net	**8**	62	**(1,914)**	(2,311)
Income before income taxes	**40,774**	34,258	**119,893**	106,905
Income tax expense	**92**	1,061	**1,715**	9,861
Net income	**40,682**	33,197	**118,178**	97,044
Net income attributable to noncontrolling interests	**3,873**	2,541	**9,665**	7,806
Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238
Key Performance Metrics (2)				
Gross margin	**$ 107,188**	$ 85,607	**$ 306,633**	$ 259,047
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 66,045**	$ 52,896	**$ 192,922**	$ 156,693
Distributable cash flow	**$ 51,338**	$ 45,490	**$ 164,768**	$ 139,843

(1) Revenues include affiliate amounts earned by the Partnership from services provided to our affiliates, as well as from sale of residue gas, condensate and NGLs to our affiliates. Operating expenses include amounts charged by our affiliates for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. See *Note 4. Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

(2) Gross margin, Adjusted EBITDA attributable to Western Gas Partners, LP (Adjusted EBITDA) and Distributable cash flow are defined under the caption *Operating results* within this Item 2. Such caption also includes reconciliations of Adjusted EBITDA and Distributable cash flow to their most directly comparable measures calculated and presented in accordance with generally accepted accounting principles (GAAP).

For purposes of the following discussion, any increases or decreases for the three months ended September 30, 2011 refer to the comparison of the three months ended September 30, 2011, to the three months ended September 30, 2010; any increases or decreases for the nine months ended September 30, 2011 refer to the comparison of the nine months ended September 30, 2011, to the nine months ended September 30, 2010; and any increases or decreases for the three and nine months ended September 30, 2011 refer to both the comparison for the three months ended September 30, 2011, and to the comparison for the nine months ended September 30, 2011.

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Operating Statistics

	Three Months Ended September 30,			Nine Months Ended September 30,		
MMcf/d except percentages	**2011**	**2010**	Δ	**2011**	**2010**	Δ
Gathering, treating and transportation throughput (1)	**1,219**	1,132	8%	**1,270**	1,089	17%
Processing throughput (2)	**917**	707	30%	**840**	668	26%
Equity investment throughput (3)	**79**	115	(31)%	**69**	117	(41)%
Total throughput (4)	**2,215**	1,954	13%	**2,179**	1,874	16%
Throughput attributable to noncontrolling interests	**258**	195	32%	**237**	194	22%
Total throughput attributable to Western Gas Partners, LP	**1,957**	1,759	11%	**1,942**	1,680	16%

(1) Excludes average NGL pipeline volumes of 25 MBbls/d and 11 MBbls/d, for the three months ended September 30, 2011 and 2010, respectively, and 23 MBbls/d and 15 MBbls/d for the nine months ended September 30, 2011 and 2010, respectively.

(2) Consists of 100% of Chipeta, Granger and Hilight system volumes and 50% of Newcastle system volumes for all periods presented as well as throughput beginning March 2011 attributable to the Platte Valley system.

(3) Represents our 14.81% share of Fort Union s gross volumes and excludes crude oil throughput measured in barrels attributable to White Cliffs.

(4) Includes affiliate, third-party and equity-investment volumes.

Gathering, treating and transportation throughput increased by 87 MMcf/d and 181 MMcf/d for the three and nine months ended September 30, 2011, respectively, primarily due to the startup of the Bison system in June 2010 and throughput increases at the Wattenberg system due to increased drilling activity in the area. These increases were partially offset by lower throughput at the MIGC system resulting from the January 2011 expiration of certain contracts that were not renewed due to the startup of the third-party owned Bison pipeline, and throughput decreases at the Haley, Pinnacle, Dew and Hugoton systems resulting from natural production declines and reduced drilling activity in those areas.

Processing throughput increased by 210 MMcf/d and 172 MMcf/d for the three and nine months ended September 30, 2011, respectively, primarily due to the additional throughput from the Platte Valley system acquired in February 2011, as well as throughput increases at the Chipeta and Hilight systems, resulting from drilling activity in these areas driven by the relatively high liquid content of the gas volumes produced.

Equity investment volumes decreased by 36 MMcf/d and by 48 MMcf/d for the three and nine months ended September 30, 2011, respectively, due to lower throughput at the Fort Union system following the startup of the Bison pipeline.

Natural Gas Gathering, Processing and Transportation Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2011**	**2010**	Δ	**2011**	**2010**	Δ
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 71,873**	$ 60,363	19%	**$ 211,418**	$ 172,769	22%

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $11.5 million and $38.6 million for the three and nine months ended September 30, 2011, respectively, due to the acquisition of the Platte Valley system, the June 2010 startup of the Bison system, and increased third-party throughput at the Chipeta system. Increases for the three months ended September 30, 2011, are also attributable to increased fee revenue at the Wattenberg system as a result of changes in affiliate contract terms (from primarily keep-whole and percentage-of-proceeds arrangements to fee-based arrangements), effective July 2010. These increases were partially offset by decreased fee revenue at MIGC due to the January 2011 expiration of certain contracts, along with decreased volume due to natural declines at the Haley, Hugoton and Dew systems.

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Natural Gas, Natural Gas Liquids and Condensate Sales

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2011	2010	Δ	Nine Months Ended September 30, 2011	2010	Δ
Natural gas sales	**$ 30,276**	$ 19,064	59%	**$ 79,965**	$ 48,652	64%
Natural gas liquids sales	**64,145**	38,053	69%	**159,361**	127,724	25%
Drip condensate sales	**6,658**	2,770	140%	**23,715**	20,416	16%
Total	**$ 101,079**	$ 59,887	69%	**$ 263,041**	$ 196,792	34%
Average price per unit:						
Natural gas (per Mcf)	**$ 5.88**	$ 5.97	(2)%	**$ 5.87**	$ 5.74	2%
Natural gas liquids (per Bbl)	**$ 51.06**	$ 41.36	23%	**$ 47.94**	$ 40.57	18%
Drip condensate (per Bbl)	**$ 76.93**	$ 67.61	14%	**$ 74.56**	$ 70.93	5%

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $41.2 million for the three months ended September 30, 2011, which consisted of a $26.1 million increase in NGLs sales, an $11.2 million increase in natural gas sales and a $3.9 million increase in drip condensate sales. The increase in natural gas sales was due to a 60% increase in the volume and the increase in NGLs sales was due to a 25% increase in the volume sold, both as a result of higher throughput at the Hilight system and the acquisition of the Platte Valley system. The increase in NGL sales was also attributable to a 23% increase in NGLs sales prices. The increase in drip condensate sales for the three months ended September 30, 2011, was primarily due to an increase in the volume and average sales prices at the Wattenberg system along with Platte Valley sales.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $66.2 million for the nine months ended September 30, 2011, which consisted of a $31.6 million increase in NGLs sales, a $31.3 million increase in natural gas sales and a $3.3 million increase in drip condensate sales. The increase in natural gas sales was due to a 60% increase in the volume of sold and a 2% increase in the average price. The increase in NGLs sales was primarily due to an 18% increase in average price and a 3% increase in volume sold. The increase in volumes was as a result of higher throughput at the Chipeta and Hilight system as well as the acquisition of the Platte Valley system, partially offset by the decrease in volumes sold at the Wattenberg system as a result of changes in affiliate contract terms (from primarily keep-whole and percentage-of-proceeds arrangements to fee-based arrangements, whereby the producer takes product in kind) effective July 2010. The increase in drip condensate sales for the nine months ended September 30, 2011, was primarily due to a higher average sales price at the Wattenberg and Hugoton systems and Platte Valley sales, partially offset by a decrease in the volume of drip condensate sold.

The average natural gas and NGLs prices for the three and nine months ended September 30, 2011, include the effects of commodity price swap agreements attributable to sales for the Granger, Wattenberg, Hilight, Newcastle and Hugoton systems. The average natural gas and NGLs prices for the three and nine months ended September 30, 2010, include the effects of commodity price swap agreements attributable to sales for only the Granger, Hilight and Newcastle systems. See *Note 4. Transactions with Affiliates Commodity price swap agreements* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

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Cost of Product and Operation and Maintenance Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2011**	**2010**	Δ	**2011**	**2010**	Δ
Cost of product	**$ 68,675**	$ 37,444	83%	**$ 177,877**	$ 117,923	51%
Operation and maintenance	**27,012**	19,924	36%	**74,628**	64,798	15%
Total cost of product and operation and maintenance expenses	**$ 95,687**	$ 57,368	67%	**$ 252,505**	$ 182,721	38%

Including the effects of commodity price swap agreements on purchases, cost of product expense increased by $31.2 million for the three months ended September 30, 2011, which includes a $14.0 million increase due to the acquisition of the Platte Valley system, and increased throughput at the Hilight and Chipeta systems.

Including the effects of commodity price swap agreements on purchases, cost of product expense increased by $60.0 million for the nine months ended September 30, 2011, which includes a $31.5 million increase due to the acquisition of the Platte Valley system, as well as increased throughput at the Hilight and Chipeta systems, partially offset by a $7.6 million decrease due to changes in gas imbalance positions.

Cost of product expense for the three and nine months ended September 30, 2011, include the effects of commodity price swap agreements attributable to purchases for the Granger, Wattenberg, Hilight, Newcastle and Hugoton systems. Cost of product expense for the three and nine months ended September 30, 2010, include the effects of commodity price swap agreements attributable to purchases for the Granger, Wattenberg, Hilight and Newcastle systems. See *Note 4. Transactions with Affiliates Commodity price swap agreements* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

During the three months ended September 30, 2011, $1.3 million of expenses, net, related to prior periods were recorded in our consolidated statements of income. As a result of a metering adjustment, we recorded $0.7 million of cost of product during the quarter, of which $0.3 million related to 2008, $0.2 million related to 2009 and $0.2 million related to 2010. In addition, as a result of a true-up of expenses related to the transition period in conjunction with the Platte Valley acquisition, we recorded $0.6 million of cost of product during the quarter, of which $0.4 million related to the first quarter of 2011 and $0.2 million related to the second quarter of 2011. Management determined the adjustments were not material to our consolidated financial statements for the years ended December 31, 2010, 2009 and 2008, nor to our interim financial statements, and accordingly, determined that restatement of our previously reported financial statements was not necessary.

Operation and maintenance expense increased by $7.1 million for the three months ended September 30, 2011, primarily due to the acquisition of the Platte Valley system, the Bison system being fully operational during 2011 compared to the gradual startup beginning June 2010 and increased field personnel at the Wattenberg system.

Operation and maintenance expense increased by $9.8 million for the nine months ended September 30, 2011, primarily due to the acquisition of the Platte Valley system and the June 2010 startup of the Bison system, partially offset by a decrease related to annual incentive compensation attributed to the Wattenberg system prior to our acquisition and lower compressor lease expenses resulting from the purchase of compressors used at the Wattenberg system leased during 2010.

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General and Administrative, Depreciation and Other Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2011**	**2010**	**Δ**	**2011**	**2010**	**Δ**
General and administrative	**$ 7,643**	$ 5,970	28%	**$ 21,777**	$ 17,600	24%
Property and other taxes	**4,411**	3,610	22%	**12,632**	10,878	16%
Depreciation, amortization and impairments	**22,650**	19,324	17%	**65,512**	54,683	20%
Total general and administrative, depreciation and other expenses	**$ 34,704**	$ 28,904	20%	**$ 99,921**	$ 83,161	20%

General and administrative expenses increased by $1.7 million and $4.2 million for the three and nine months ended September 30, 2011, respectively, due to an increase in noncash payroll expenses primarily due to an increase in the value of incentive plan awards.

Property and other taxes increased by $0.8 million and $1.8 million for the three and nine months ended September 30, 2011, respectively, primarily due to the ad valorem tax for the Bison, Platte Valley and Wattenberg assets.

Depreciation, amortization and impairments increased by $3.3 million and $10.8 million for the three and nine months ended September 30, 2011, respectively, primarily attributable to the addition of the Bison and Platte Valley systems, and depreciation associated with capital projects completed and capitalized at the Wattenberg, Hugoton and Hilight systems.

Interest Income and Interest Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2011**	**2010**	**Δ**	**2011**	**2010**	**Δ**
Interest income affiliates	**$ 4,225**	$ 4,225	%	**$ 12,675**	$ 12,675	%
Third Parties						
Interest expense on long-term debt	**(6,739)**	(3,012)	124%	**(13,889)**	(5,119)	171%
Amortization of debt issuance costs and commitment fees	**(1,078)**	(860)	25%	**(4,282)**	(2,309)	85%
Capitalized interest	**121**		nm(1)	**134**		nm(1)
Affiliates						
Interest expense on notes payable	**(1,234)**	(1,750)	(29)%	**(3,701)**	(5,250)	(30)%
Interest expense, net on affiliate balances (2)	**(1)**	(1,160)	(100)%	**(1,214)**	(1,773)	(32)%
Credit facility commitment fees		(26)	(100)%		(96)	(100)%
Interest expense	**$ (8,931)**	$ (6,808)	31%	**$ (22,952)**	$ (14,547)	58%

(1) Percent change is not meaningful (nm).

(2) Incurred on intercompany borrowings associated with the Bison assets in 2011, and associated with the Bison assets, White Cliffs investment and Wattenberg assets in 2010, prior to such assets being acquired by the Partnership.

Interest expense increased by $2.1 million and $8.4 million for the three and nine months ended September 30, 2011, respectively, due to interest expense incurred on the 5.375% Senior Notes issued in May 2011, interest expense during 2011 under the Wattenberg term loan (described in *Liquidity and Capital Resources*), as well as $1.3 million of accelerated amortization expense related to the early repayment of the Wattenberg term loan in March 2011. This increase is partially offset by a decrease in interest expense on the Note Payable to Anadarko, which was amended in December 2010 reducing the interest rate from 4.00% to 2.82% for the remainder of the term, and lower interest expense on amounts outstanding on our revolving credit facility during 2011. See *Note 7. Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* included under Part I, Item 1 of this Form 10-Q.

Other Income (Expense), Net

thousands except percentages	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Δ	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Δ
Other income (expense), net	**$ 8**	$ 62	(87)%	**$ (1,914)**	$ (2,311)	(17)%

Other income (expense), net for the nine months ended September 30, 2011, primarily consists of the $1.9 million loss realized on the interest-rate swap agreement entered into in March 2011 and terminated in May 2011. Other income (expense), net for the nine months ended September 30, 2010, primarily relates to financial agreements entered into in April 2010 to fix the underlying ten-year Treasury rates with respect to potential note issuances that were under consideration at that time. Upon reaching our decision not to issue the notes in May 2010, we terminated the agreements at a cost of $2.4 million.

Income Tax Expense

thousands except percentages	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Δ	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Δ
Income before income taxes	**$ 40,774**	$ 34,258	19%	**$ 119,893**	$ 106,905	12%
Income tax expense	**92**	1,061	(91)%	**1,715**	9,861	(83)%
Effective tax rate	**%**	3%		**1%**	9%	

We are not a taxable entity for U.S. federal income tax purposes, although the portion of our income apportionable to Texas is subject to Texas margin tax. Income attributable to (a) the Bison assets prior to and including June 2011, (b) the Wattenberg assets prior to and including July 2010 and (c) the Granger assets prior to and including January 2010 were subject to federal and state income tax, resulting in the lower income tax expense for the three and nine months ended September 30, 2011. Income earned by the Granger, Wattenberg and Bison assets for periods subsequent to January 2010, July 2010 and June 2011, respectively, was subject only to Texas margin tax on the portion of their incomes apportionable to Texas.

For 2011 and 2010, the Partnership s variance from the federal statutory rate is primarily attributable to the Partnership s status as a non-taxable entity for U.S. federal income tax purposes.

Noncontrolling Interests

thousands except percentages	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Δ	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Δ
Net income attributable to noncontrolling interests	**$3,873**	$2,541	52%	**$9,665**	$7,806	24%

For the three and nine months ended September 30, 2011, net income attributable to noncontrolling interests increased by $1.3 million and $1.9 million, respectively, primarily due to the higher volumes and improved liquids recoveries at the Chipeta system.

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Key Performance Metrics

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages and gross margin per Mcf	**2011**	**2010**	**Δ**	**2011**	**2010**	**Δ**
Gross margin	**$ 107,188**	$ 85,607	25%	**$ 306,633**	$ 259,047	18%
Gross margin per Mcf (1)	**0.53**	0.48	10%	**0.52**	0.51	2%
Gross margin per Mcf attributable to Western Gas Partners, LP (2)	**0.56**	0.50	12%	**0.55**	0.54	2%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	**66,045**	52,896	25%	**192,922**	156,693	23%
Distributable cash flow (3)	**$ 51,338**	$ 45,490	13%	**$ 164,768**	$ 139,843	18%

(1) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total throughput, including 100% of gross margin and volumes attributable to Chipeta and our 14.81% interest in income and volumes attributable to Fort Union.

(2) Average for period. Calculated as gross margin, excluding the noncontrolling interest owners proportionate share of revenues and cost of product, divided by total throughput attributable to Western Gas Partners, LP. Calculation includes income attributable to our investments in Fort Union and White Cliffs and volumes attributable to our investment in Fort Union.

(3) For a reconciliation of Adjusted EBITDA and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read the descriptions below under the captions *Adjusted EBITDA* and *Distributable cash flow*.

Gross margin and Gross margin per Mcf. Gross margin increased by $21.6 million and $47.6 million for the three and nine months ended September 30, 2011, respectively, primarily due to the acquisition of the Platte Valley system; higher margins at the Wattenberg, Chipeta and Hilight systems due to an increase in volumes, including the impact of commodity price swap agreements at the Wattenberg and Hilight system; the increase in our interest in White Cliffs from 0.4% to 10% in September 2010; and the start-up of the Bison system in June 2010. These increases were partially offset by lower gross margins at the Dew, Granger and Hugoton systems due to naturally declining production volumes and lower gross margin at the MIGC system due to the expiration of certain firm transportation contracts in January 2011. For the three and nine months ended September 30, 2011, gross margin per Mcf increased by 10% and 2%, respectively, and gross margin per Mcf attributable to Western Gas Partners, LP increased by 12% and 2%, respectively, primarily due to the acquisition of the Platte Valley system in 2011, the additional interest in the White Cliffs system in September 2010 and changes in the throughput mix of the portfolio.

Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, general and administrative expense in excess of the omnibus cap (if any), interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, other income and other nonrecurring adjustments that are not settled in cash.

We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company s ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure, which management and external users of our consolidated financial statements, such as industry analysts, investors, commercial banks and rating agencies, use to assess the following, among other measures:

our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;

the ability of our assets to generate cash flow to make distributions; and

the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Adjusted EBITDA increased by $13.1 million for the three months ended September 30, 2011, primarily due to a $52.4 million increase in total revenues excluding equity income, partially offset by a $31.2 million increase in cost of product, and a $7.1 million increase in operation and maintenance expenses. Adjusted EBITDA increased by $36.2 million for the nine months ended September 30, 2011, primarily due to a $105.2 million increase in total revenues excluding equity income, partially offset by a $60.0 million increase in cost of product, and a $9.8 million increase in operation and maintenance expenses.

Distributable cash flow. We define Distributable cash flow as Adjusted EBITDA, plus interest income, less net cash paid for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, and income taxes. We believe Distributable cash flow is useful to investors because this measurement is used by many companies, analysts and others in the industry as a performance measurement tool to evaluate our operating and financial performance and compare it with the performance of other publicly traded partnerships. We also compare Distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions.

Distributable cash flow increased by $5.8 million for the three months ended September 30, 2011, primarily due to the $13.1 million increase in Adjusted EBITDA, partially offset by a $3.7 million increase in cash paid for maintenance capital expenditures and a $3.4 million increase in net cash paid for interest expense.

Distributable cash flow increased by $24.9 million for the nine months ended September 30, 2011, primarily due to the $36.2 million increase in Adjusted EBITDA, partially offset by a $9.1 million increase in net cash paid for interest expense and a $2.0 million decrease in cash paid for maintenance capital expenditures.

Reconciliation to GAAP measures. Adjusted EBITDA and Distributable cash flow are not defined in GAAP. The GAAP measures most directly comparable to Adjusted EBITDA are net income attributable to Western Gas Partners, LP and net cash provided by operating activities, while the GAAP measure most directly comparable to Distributable cash flow is net income attributable to Western Gas Partners, LP. Our non-GAAP financial measures of Adjusted EBITDA and Distributable cash flow should not be considered as alternatives to the GAAP measures of net income attributable to Western Gas Partners, LP or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some, but not all, items that affect net income and net cash provided by operating activities. You should not consider Adjusted EBITDA or Distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Our definitions of Adjusted EBITDA and Distributable cash flow may not be comparable to similarly titled measures of other companies in our industry, thereby diminishing their utility. Furthermore, while Distributable cash flow is a measure we use to assess our performance and our ability to make distributions to our unitholders, it should not be viewed as indicative of the actual amount of cash that we have available for distributions or that we plan to distribute for a given period.

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Management compensates for the limitations of Adjusted EBITDA and Distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted EBITDA and Distributable cash flow compared to (as applicable) net income and net cash provided by operating activities, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

The following tables present (a) a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income attributable to Western Gas Partners, LP and net cash provided by operating activities, and (b) a reconciliation of the non-GAAP financial measure of Distributable cash flow to the GAAP financial measure of net income attributable to Western Gas Partners, LP:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2011**	**2010**	**2011**	**2010**
Reconciliation of Adjusted EBITDA to Net income attributable to Western Gas Partners, LP				
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 66,045**	$ 52,896	**$ 192,922**	$ 156,693
Less:				
Distributions from equity investees	**2,426**	1,381	**7,873**	3,619
Non-cash equity-based compensation expense	**2,389**	569	**6,235**	1,817
Interest expense	**8,931**	6,808	**22,952**	14,547
Income tax expense (1)	**92**	1,061	**1,715**	9,861
Depreciation, amortization and impairments (1)	**21,928**	18,619	**63,380**	52,572
Other expense (1)			**3,683**	2,393
Add:				
Equity income, net	**2,299**	1,912	**6,989**	4,599
Interest income affiliates	**4,225**	4,225	**12,675**	12,675
Other income (1)	**6**	61	**1,765**	80
Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238
Reconciliation of Adjusted EBITDA to Net cash provided by operating activities				
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 66,045**	$ 52,896	**$ 192,922**	$ 156,693
Adjusted EBITDA attributable to noncontrolling interests	**4,593**	3,245	**11,793**	9,915
Interest income (expense), net	**(4,706)**	(2,583)	**(10,277)**	(1,872)
Non-cash equity-based compensation expense	**(2,389)**	(569)	**(6,235)**	(1,817)
Current income tax expense	**(83)**	3,147	**3,465**	(7,869)
Other income (expense), net	**8**	62	**(1,914)**	(2,311)
Distributions from equity investees less than (in excess of) equity income, net	**(127)**	531	**(884)**	980
Changes in operating working capital:				
Accounts receivable and natural gas imbalance receivable	**51**	5,087	**(19,102)**	(1,230)
Accounts payable, accrued liabilities and natural gas imbalance payable	**15,876**	3,345	**29,642**	11,451

Other	**(1,616)**	(8,106)	**1,320**	(8,231)
Net cash provided by operating activities	**$ 77,652**	$ 57,055	**$ 200,730**	$ 155,709

(1) Includes our 51% share of income tax expense; depreciation, amortization and impairments; other expense; and other income attributable to Chipeta.

thousands	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP				
Distributable cash flow	**$ 51,338**	$ 45,490	**$ 164,768**	$ 139,843
Less:				
Distributions from equity investees	**2,426**	1,381	**7,873**	3,619
Non-cash equity-based compensation expense	**2,389**	569	**6,235**	1,817
Interest expense, net (non-cash settled)		1,160	**1,214**	1,772
Income tax expense (1)	**92**	1,061	**1,715**	9,861
Depreciation, amortization and impairments (1)	**21,928**	18,619	**63,380**	52,572
Other expense (1)			**3,683**	2,393
Add:				
Equity income, net	**2,299**	1,912	**6,989**	4,599
Cash paid for maintenance capital expenditures (1)	**9,690**	5,983	**18,767**	16,750
Capitalized interest	**121**		**134**	
Cash paid for income taxes	**190**		**190**	
Other income (1)	**6**	61	**1,765**	80
Net income attributable to Western Gas Partners, LP	**$ 36,809**	$ 30,656	**$ 108,513**	$ 89,238

(1) Includes our 51% share of income tax expense; depreciation, amortization and impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to Chipeta.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and other capital expenditures, debt service, customary operating expenses, quarterly distributions to our limited partners and general partner, and distributions to our noncontrolling interest owners. Our sources of liquidity as of September 30, 2011, include cash flows generated from operations, including interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our revolving credit facility, and issuances of additional common and general partner units or debt securities. We believe that cash flows generated from the sources above will be sufficient to satisfy our short-term working capital requirements and long-term maintenance capital expenditure requirements. The amount of future distributions to unitholders will depend on results of operations, financial conditions, capital requirements and other factors, and will be determined by the board of directors of our general partner on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including debt and common unit issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under our revolving credit facility to pay distributions or fund other short-term working capital requirements.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders and have increased our quarterly distribution each quarter from the second quarter of 2009 through the third quarter of 2011. On October 12, 2011, the board of directors of our general partner declared a cash distribution to our unitholders of $0.42 per unit, or $40.3 million in aggregate, including incentive distributions. The cash distribution is payable on November 10, 2011, to unitholders of record at the close of business on October 31, 2011.

Management continuously monitors our leverage position and coordinates its capital expenditure program, quarterly distributions and acquisition strategy with its expected cash flows and projected debt-repayment schedule.

We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or to refinance outstanding debt balances with longer-term notes. To facilitate a potential debt or equity securities issuance, we have the ability to sell securities under our shelf registration statement. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read *Item 1A Risk Factors* of our 2010 annual report on Form 10-K.

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Working capital. As of September 30, 2011, we had $203.6 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital is an indication of our liquidity and potential need for short-term funding. Our working-capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers and the level and timing of our spending for maintenance and expansion activity.

Capital expenditures. Our business can be capital intensive, requiring significant investment to maintain and improve existing facilities. We categorize capital expenditures as either of the following:

maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, such as to replace system components and equipment that have been subject to significant use over time, become obsolete or reached the end of their useful lives, to remain in compliance with regulatory or legal requirements or to complete additional well connections to maintain existing system throughput and related cash flows; or

expansion capital expenditures, which include those expenditures incurred in order to extend the useful lives of our assets, reduce costs, increase revenues or increase system throughput or capacity from current levels, including well connections that increase existing system throughput.

Capital expenditures in the consolidated statements of cash flows reflect capital expenditures on a cash basis, when payments are made. Capital incurred is presented on an accrual basis. Capital expenditures and capital incurred were as follows:

	Nine Months Ended September 30,	
thousands	**2011**	**2010**
Acquisitions	**$ 326,957**	$ 752,827
Expansion capital expenditures	**$ 56,171**	$ 88,587
Maintenance capital expenditures	**18,863**	16,958
Total capital expenditures [(1)]	**$ 75,034**	$ 105,545
Capital incurred [(2)]	**$ 84,675**	$ 117,831

(1) Capital expenditures for the nine months ended September 30, 2011 and 2010, includes $6.0 million and $83.2 million, respectively, of pre-acquisition capital expenditures for the Bison and Wattenberg assets and includes the noncontrolling interest owners share of Chipeta s capital expenditures, funded by contributions from the noncontrolling interest owners.

(2) Capital incurred for the nine months ended September 30, 2011 and 2010, includes $4.4 million and $95.2 million, respectively, of pre-acquisition capital incurred for the Bison and Wattenberg assets and includes the noncontrolling interest owners share of Chipeta s capital incurred, funded by contributions from the noncontrolling interest owners.

Acquisitions include the Bison, Platte Valley, White Cliffs, Wattenberg and Granger acquisitions as outlined under the caption *Acquisitions* within this Item 2.

Capital expenditures, excluding acquisitions, decreased by $30.5 million for the nine months ended September 30, 2011. Expansion capital expenditures decreased by $32.4 million for the nine months ended

September 30, 2011, primarily due to the purchase of previously leased compressors at the Wattenberg system during the nine months ended September 30, 2010 for $37.5 million, partially offset by an increase of $5.1 million in expenditures primarily at our Bison, Chipeta and Hilight systems. Maintenance capital expenditures increased by $1.9 million, primarily as a result of maintenance projects at the Wattenberg system, higher well connects at the Hilight system and power system upgrades at the Dew system in 2011, partially offset by fewer well connections at the Haley and Hugoton systems in 2011 and improvements at the Granger system completed during 2010.

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Historical cash flow. The following table presents a summary of our net cash flows from operating activities, investing activities and financing activities.

thousands	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Net cash provided by (used in):		
Operating activities	**$ 200,730**	$ 155,709
Investing activities	**(401,702)**	(853,452)
Financing activities	**425,356**	664,159
Net increase (decrease) in cash and cash equivalents	**$ 224,384**	$ (33,584)

Operating Activities. Net cash provided by operating activities increased by $45.0 million for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010, primarily due to the following items:

a $105.2 million increase in revenues, excluding equity income;

a $26.2 million increase due to changes in accounts payable balances and other items; and

an $11.3 million decrease in current income tax expense.

The impact of the above items was offset by the following:

a $60.0 million increase in cost of product expense;

a $16.3 million decrease due to changes in accounts receivable balances;

a $9.8 million increase in operation and maintenance expenses.

an $8.4 million increase in interest expense; and

a $1.8 million increase in property and other taxes expense.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2011 included $302.0 million of cash paid for the Platte Valley acquisition, net of the final $1.6 million purchase price allocation adjustment; $25.0 million of cash paid for the Bison acquisition; and $75.0 million of capital expenditures. Net cash used in investing activities for the nine months ended September 30, 2010 included $473.1 million paid for the Wattenberg acquisition, $241.7 million of cash paid for the Granger acquisition, $38.0 million paid for the White Cliffs acquisition and $105.5 million of capital expenditures. Offsetting these amounts were $5.2 million of proceeds from the sale of idle compressors to Anadarko and the sale of an idle refrigeration unit at the Granger system to a third party. See the sub-caption *Capital expenditures* above within this *Liquidity and Capital Resources* discussion.

Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2011 included $303.0 million of borrowings to fund the Platte Valley acquisition, $202.8 million of net proceeds from our September 2011 equity offering, $132.6 million of net proceeds from our March 2011 equity offering and $493.9 million net proceeds from our Notes offering in May 2011, after debt discount and offering costs. Proceeds from both our March 2011 equity offering and Notes offering in May 2011 were used to offset amounts outstanding under our revolving credit facility. Financing activities for the nine months ended September 30, 2011 also included the $250.0 million repayment of the Wattenberg term loan (described below) using borrowings from our revolving credit facility. Financing activities for the nine months ended September 30, 2010 included $450.0 million of borrowings to partially fund the Wattenberg acquisition, $210.0 million to partially fund the Granger acquisition and $99.1 million of net proceeds from the May 2010 equity offering, offset by the $100.0 million repayment of our revolving credit facility using such proceeds. For the nine months ended September 30, 2011 and 2010 we paid $99.8 million and $67.8 million, respectively, of cash distributions to our unitholders. Contributions from noncontrolling interest owners to Chipeta totaled $16.9 million and $2.1 million during the nine months ended September 30, 2011 and 2010, respectively, primarily for expansion of the cryogenic units. Distributions from Chipeta to noncontrolling interest owners totaled $10.2 million and $10.3 million for the nine months ended September 30, 2011 and 2010, respectively, representing the distributions for the three preceding quarterly periods ended June 30th of the respective year.

Debt and credit facilities. As of September 30, 2011, our outstanding debt consisted of $494.1 million of 5.375% Senior Notes and the $175.0 million note payable to Anadarko. See *Note 7. Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* included under Part I, Item 1 of this Form 10-Q.

5.375% Senior Notes due 2021. In May 2011, we completed the offering of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the Notes) at a price to the public of 98.778% of the face amount of the Notes. Interest on the Notes will be paid semi-annually on June 1 and December 1 of each year, commencing on December 1, 2011. The Notes mature on June 1, 2021, unless redeemed, in whole or in part, at any time prior to maturity, at a redemption price that includes a make-whole premium. Proceeds from the offering of the Notes (net of the underwriting discount of $3.3 million and debt issuance costs) were used to repay the then-outstanding balance on the revolving credit facility, with the remainder used for general partnership purposes.

The Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our wholly owned subsidiaries (the Subsidiary Guarantors). The Subsidiary Guarantors guarantees will be released if, among other things, the Subsidiary Guarantors are released from their obligations under our revolving credit facility.

The Notes indenture contains customary events of default including, among others, (i) default in any payment of interest on any debt securities when due that continues for 30 days; (ii) default in payment, when due, of principal of or premium, if any, on the Notes at maturity; and (iii) certain events of bankruptcy or insolvency with respect to the Partnership. The indenture governing the Notes also contains covenants that limit, among other things, our ability, as well as that of the Subsidiary Guarantors, to (i) create liens on our principal properties; (ii) engage in sale and leaseback transactions; and (iii) merge or consolidate with another entity or sell, lease or transfer substantially all of our properties or assets to another entity. At September 30, 2011, we were in compliance with all covenants under the Notes.

Note payable to Anadarko. In December 2008, we entered into a five-year $175.0 million term loan agreement with Anadarko. The interest rate was fixed at 4.00% until November 2010. The term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity in 2013. We have the option, at any time, to repay the outstanding principal amount in whole or in part.

The provisions of the five-year term loan agreement contain customary events of default, including (i) non-payment of principal when due or non-payment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership and (iii) a change of control. At September 30, 2011, we were in compliance with all covenants under this agreement.

Revolving credit facility. In March 2011, we entered into an amended and restated $800.0 million senior unsecured revolving credit facility (the RCF), which replaced our $450.0 million credit facility, and borrowed $250.0 million under the RCF to repay the Wattenberg term loan (described below). The RCF matures in March 2016 and bears interest at London Interbank Offered Rate, or LIBOR, plus applicable margins currently ranging from 1.30% to 1.90%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, and (c) LIBOR plus 1%, plus applicable margins currently ranging from 0.30% to 0.90%. We are also required to pay a quarterly facility fee currently ranging from 0.20% to 0.35% of the commitment amount (whether used or unused), based upon our senior unsecured debt rating.

The RCF contains covenants that limit, among other things, our, and certain of our subsidiaries , ability to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of our business, sell all or substantially all of our assets, make certain transfers, enter into certain affiliate transactions, make distributions or other payments other than distributions of available cash under certain conditions and use proceeds other than for partnership purposes. The RCF also contains various customary covenants, customary events of default and certain financial tests, as of the end of each quarter, including a maximum consolidated leverage ratio, as defined in the RCF, of 5.0 to 1.0, or a consolidated leverage ratio of 5.5 to 1.0 with respect to quarters ending in the 270-day period immediately following certain acquisitions, and a minimum consolidated interest coverage ratio, as defined in the RCF, of 2.0 to 1.0.

All amounts due under the RCF are unconditionally guaranteed by our wholly owned subsidiaries. We will no longer be required to comply with the minimum consolidated interest coverage ratio as well as the subsidiary guarantees and certain of the aforementioned covenants, if we obtain two of the following three ratings: BBB- or better by S&P, Baa3 or better by Moody s, or BBB- or better by Fitch. As of September 30, 2011, no amounts were outstanding under the RCF, and $800.0 million was available for borrowing. At September 30, 2011, we were in compliance with all covenants under the RCF.

Wattenberg term loan. In connection with the Wattenberg acquisition, in August 2010 we borrowed $250.0 million under a three-year term loan from a group of banks (Wattenberg term loan). The Wattenberg term loan incurred interest at LIBOR plus a margin ranging from 2.50% to 3.50% depending on our consolidated leverage ratio as defined in the Wattenberg term loan agreement. We repaid the Wattenberg term loan in March 2011 using borrowings from our RCF and recognized $1.3 million of accelerated amortization expense related to its early repayment.

Registered securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statement on file with the SEC.

Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. Generally, non-payment or non-performance results from a customer s inability to satisfy payables to us for services rendered or volumes owed pursuant to gas imbalance agreements. We examine and monitor the creditworthiness of third-party customers and may establish credit limits for third-party customers.

We are dependent upon a single producer, Anadarko, for the substantial majority of our natural gas volumes and we do not maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, processing and transportation fees and for proceeds from the sale of residue gas, NGLs and condensate to Anadarko.

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko, which was issued concurrently with the closing of our initial public offering. We are also party to agreements with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes with respect to the assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to commodity price risk and are subject to performance risk thereunder.

Our ability to make distributions to our unitholders may be adversely impacted if Anadarko becomes unable to perform under the terms of our gathering, processing and transportation agreements, natural gas and NGL purchase agreements, its note payable to us, the omnibus agreement, the services and secondment agreement, contribution agreements or the commodity price swap agreements.

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CONTRACTUAL OBLIGATIONS

Our contractual obligations include a note payable to Anadarko, a revolving credit facility, other third-party long-term debt, a corporate office lease and warehouse lease, for which information is provided in *Note 7. Debt and Interest Expense* and *Note 8. Commitments and Contingencies* included in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q. Our contractual obligations also include asset retirement obligations, which have not changed significantly since December 31, 2010, except for asset retirement obligations assumed in connection with the Platte Valley acquisition for which information is provided under *Note 1. Description of Business and Basis of Presentation Acquisitions* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases. The information pertaining to operating leases required for this item is provided under *Note 8. Commitments and Contingencies* included in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

RECENT ACCOUNTING DEVELOPMENTS

Recently issued accounting standards not yet adopted. In May 2011, the Financial Accounting Standards Board (the FASB) issued an Accounting Standards Update (ASU) that further addresses fair-value-measurement accounting and related disclosure requirements. The ASU clarifies the FASB s intent regarding the application of existing fair-value-measurement accounting and disclosure requirements, changes fair-value-measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair-value measurements. The ASU is required to be adopted on a prospective basis beginning January 1, 2012. We do not expect the adoption of this ASU to have an impact on our consolidated financial statements, other than revised disclosures, where appropriate.

In September 2011, the FASB issued an ASU that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit s fair value is not required unless, as a result of the qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective prospectively beginning January 1, 2012, with early adoption permitted. Adoption of this ASU will have no impact on our consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk. Pursuant to certain of our contracts, we retain and sell drip condensate that is recovered during the gathering of natural gas. As part of this arrangement, we are required to provide a thermally equivalent volume of natural gas or the cash equivalent thereof to the shipper. Thus, our revenues for this portion of our contractual arrangement are based on the price received for the drip condensate and our costs for this portion of our contractual arrangement depend on the price of natural gas. Historically, drip condensate sells at a price representing a discount to the price of New York Mercantile Exchange, or NYMEX, West Texas Intermediate crude oil.

In addition, certain of our processing services are provided under percent-of-proceeds and keep-whole agreements in which Anadarko is typically responsible for the marketing of the natural gas and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of natural gas and NGLs. Under keep-whole agreements, we keep 100% of the NGLs produced, and the processed natural gas, or value of the gas, is returned to the producer. Since some of the gas is used and removed during processing, we compensate the producer for this amount of gas by supplying additional gas or by paying an agreed-upon value for the gas utilized.

To mitigate our exposure to changes in commodity prices as a result of the purchase and sale of natural gas, condensate or NGLs, we currently have in place fixed-price swap agreements with Anadarko expiring at various times through September 2015. For additional information on the commodity price swap agreements, see *Note 4. Transactions with Affiliates Commodity price swap agreements* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

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We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the existence of the commodity price swap agreements with Anadarko and the relatively small amount of our operating income that is impacted by changes in market prices. Accordingly, we do not expect a 10% change in natural gas or NGL prices to have a material direct impact on our operating income, financial condition or cash flows for the next twelve months, excluding the effect of natural gas imbalances described below.

We also bear a limited degree of commodity price risk with respect to settlement of our natural gas imbalances that arise from differences in gas volumes received into our systems and gas volumes delivered by us to customers. Natural gas volumes owed to or by us that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by us are valued at our weighted average cost of natural gas as of the balance sheet dates and are settled in-kind. Our exposure to the impact of changes in commodity prices on outstanding imbalances depends on the timing of settlement of the imbalances.

Interest rate risk. Interest rates during 2010 and thus far in 2011 were low compared to historic rates. Only our revolving credit facility carries interest at variable rates based on LIBOR, and we did not have an outstanding balance as of September 30, 2011. If interest rates rise, our future financing costs could increase if we incur borrowings under our revolving credit facility.

We entered into a forward-starting interest-rate swap agreement in March 2011 to mitigate the risk of rising interest rates prior to the issuance of the Notes. In May 2011, we issued the Notes and terminated the swap agreement, realizing a loss of $1.9 million, which is included in other expense, net on our consolidated statements of income. For the three months ended September 30, 2011, a 10% change in LIBOR would have resulted in a nominal change in interest expense.

We may incur additional debt in the future, either under our revolving credit facility or other financing sources, including commercial bank borrowings or debt issuances.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership s general partner performed an evaluation of the Partnership s disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the rules and forms of the SEC and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Partnership s disclosure controls and procedures are effective as of September 30, 2011.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2011, that has materially affected, or is reasonably likely to materially affect, the Partnership s internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal, regulatory or administrative proceedings other than proceedings arising in the ordinary course of our business. Management believes that there are no such proceedings for which final disposition could have a material adverse effect on our financial condition, results of operations or cash flows, or for which disclosure is required by Item 103 of Regulation S-K.

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Item 1A. Risk Factors

Security holders and potential investors in our securities should carefully consider the risk factors below and under Part 1, Item 1A set forth in our annual report on Form 10-K for the year ended December 31, 2010, together with all of the other information included in this document; the Partnership s annual report on Form 10-K; and in our other public filings, press releases, and discussions with management of the Partnership. Additionally, for a full discussion of the risks associated with Anadarko s business, see Item 1A under Part I in Anadarko s annual report on Form 10-K for the year ended December 31, 2010, Anadarko s quarterly reports on Form 10-Q and Anadarko s other public filings, press releases and discussions with Anadarko management. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

Pipeline safety legislation and regulations expanding integrity management programs or requiring the use of certain safety technologies could require us to use more comprehensive and stringent safety controls and subject us to increased capital and operating costs.

Congress is currently considering adopting legislation that would establish more stringent pipeline safety requirements. The proposed legislation, if adopted, could impose strengthened pipeline integrity management system requirements, including expanding those requirements to pipelines outside high consequence areas, as well as more stringent non-integrity pipeline measures such as the use of automatic or remote-controlled shut-off valves on pipeline facilities. In addition, on May 5, 2011, the federal Pipeline and Hazardous Materials Safety Administration, or PHMSA, published a final rule expanding pipeline safety requirements including added reporting obligations and integrity management standards to certain rural low-stress hazardous liquid pipelines that were not previously regulated in such manner. Also, on August 25, 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines, gathering lines and related facilities including, among other things, whether PHMSA should: (i) re-define the term gathering line, (ii) require the submission of annual, incident and safety-related conditions reports by operators of all gathering lines, (iii) establish a new, risk-based regime of safety requirements for large-diameter, high pressure gas gathering lines in rural locations, (iv) enhance the requirements for internal corrosion control of gathering lines, and (v) apply its gas integrity management requirements to onshore gas gathering lines. The adoption of legislation or regulations that apply more comprehensive or stringent safety standards to gathering lines could require us to install new or modified safety controls, pursue added capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant and have a material adverse effect on our financial position or results of operations and our ability to make distributions to our unitholders.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and gas wells, which could decrease the need for our midstream services.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the U.S. Environmental Protection Agency, or EPA, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents on regulatory requirements for companies that plan to conduct hydraulic fracturing using diesel. In addition, legislation has been introduced before Congress, called the Fracturing Responsibility and Awareness of Chemicals Act, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process.

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Certain states in which we operate, including Colorado, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas, or RCT, and the public of certain information regarding the substances used in the hydraulic fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event that state, local or municipal legal restrictions are adopted in areas where our customers oil and gas exploration and production customers operate, those operators may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of natural gas wells, which events could decrease the need for our midstream services.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

Additionally, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities & Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanism.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells by our oil and gas exploration and production customers, in addition to increased compliance costs and time, which events could decrease the need for our midstream services and could adversely affect our financial position, results of operations and cash flows, and our ability to make distributions to our unitholders.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

In connection with our September 2011 equity offering, our general partner purchased an additional 117,347 general partner units to maintain its 2.0% general partner interest in us for $4.2 million in cash. Proceeds from the September 2011 equity offering, including from the sale of the general partner units, will be used for general Partnership purposes, and to repay amounts outstanding under our revolving credit facility. The common units and general partner units were issued in reliance on an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended.

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Item 6. Exhibits

Exhibits designated by an asterisk (*) are filed herewith and those designated with asterisks (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

2.1 Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).

2.2 Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).

2.3 Contribution Agreement, dated as of July 10, 2009, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Anadarko Uintah Midstream, LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).

2.4 Contribution Agreement, dated as of January 29, 2010 by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Mountain Gas Resources LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on February 3, 2010 File No. 001-34046).

2.5 Contribution Agreement, dated as of July 30, 2010, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).

2.6 Purchase and Sale Agreement, dated as of January 14, 2011, by and among Western Gas Partners, LP, Kerr-McGee Gathering LLC and Encana Oil & Gas (USA) Inc. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on January 18, 2011 File No. 001-34046).

3.1 Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).

3.2 First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).

3.3 Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).

3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).

3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated July 22, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated January 29, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
3.7	Amendment No. 5 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 2, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
3.8	Amendment No. 6 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated July 8, 2011 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on July 8, 2011, File No. 001-34046).
3.9	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.3 to Western Gas Partners, LP s Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.10	Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated as of May 14, 2008 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
4.2	Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.3	First Supplemental Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.4	Form of 5.375% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP s Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

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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.

WESTERN GAS PARTNERS, LP

November 2, 2011

/s/ Donald R. Sinclair
Donald R. Sinclair
President and Chief Executive Officer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)

November 2, 2011

/s/ Benjamin M. Fink
Benjamin M. Fink
Senior Vice President, Chief Financial Officer and Treasurer
Western Gas Holdings, LLC
(as general partner of Western Gas Partners, LP)