Western Gas Partners LP
Form 10-Q
November 01, 2012
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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, 2012

Or

¨ **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 ¨

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 ¨

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 ¨	Non-accelerated filer ¨ (Do not check if smaller reporting company)	Smaller reporting company ¨

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

There were 95,934,351 common units outstanding as of October 29, 2012.

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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.

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: 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, 2012**	**2011 (1)**	**Nine Months Ended September 30, 2012**	**2011 (1)**
Revenues affiliates				
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 57,459**	$ 54,551	**$ 170,461**	$ 161,665
Natural gas, natural gas liquids and condensate sales	**115,132**	117,839	**324,793**	310,337
Equity income and other, net	**4,085**	2,661	**12,219**	9,279
Total revenues affiliates	**176,676**	175,051	**507,473**	481,281
Revenues third parties				
Gathering, processing and transportation of natural gas and natural gas liquids	**20,760**	21,135	**65,388**	60,767
Natural gas, natural gas liquids and condensate sales	**20,974**	20,021	**62,025**	61,463
Other, net	**610**	1,339	**1,717**	4,557
Total revenues third parties	**42,344**	42,495	**129,130**	126,787
Total revenues	**219,020**	217,546	**636,603**	608,068
Operating expenses				
Cost of product (2)	**89,107**	89,666	**254,719**	240,765
Operation and maintenance (2)	**33,261**	31,773	**97,041**	87,859
General and administrative (2)	**14,554**	8,597	**34,233**	24,630
Property and other taxes	**5,328**	4,629	**14,998**	13,302
Depreciation, amortization and impairments	**27,528**	28,935	**81,270**	78,413
Total operating expenses	**169,778**	163,600	**482,261**	444,969
Operating income	**49,242**	53,946	**154,342**	163,099
Interest income, net affiliates	**4,225**	8,573	**12,675**	18,992
Interest expense (3)	**(10,977)**	(8,930)	**(30,118)**	(21,738)
Other income (expense), net	**522**	258	**(287)**	(895)
Income before income taxes	**43,012**	53,847	**136,612**	159,458
Income tax expense	**72**	4,668	**699**	15,564
Net income	**42,940**	49,179	**135,913**	143,894
Net income attributable to noncontrolling interests	**3,423**	3,873	**11,956**	9,665
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229

Limited partners interest in net income:				
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229
Pre-acquisition net (income) loss allocated to Anadarko		(8,497)		(28,497)
General partner interest in net (income) loss [4]	**(8,042)**	(2,394)	**(18,508)**	(5,684)
Limited partners interest in net income [4]	**$ 31,475**	$ 34,415	**$ 105,449**	$ 100,048
Net income per common unit basic and diluted	**$ 0.33**	$ 0.41	**$ 1.14**	$ 1.32
Net income per subordinated unit basic and diluted [5]	**$**	$	**$**	$ 0.96

(1) Financial information has been recast to include the financial position and results attributable to the MGR assets. See *Note 2*.

(2) Cost of product includes product purchases from Anadarko (as defined in *Note 1)* of $42.8 million and $115.6 million for the three and nine months ended September 30, 2012, respectively, and $22.8 million and $59.7 million for the three and nine months ended September 30, 2011, respectively. Operation and maintenance includes charges from Anadarko of $12.6 million and $38.0 million for the three and nine months ended September 30, 2012, respectively, and $13.6 million and $38.7 million for the three and nine months ended September 30, 2011, respectively. General and administrative includes charges from Anadarko of $13.7 million and $29.4 million for the three and nine months ended September 30, 2012, respectively, and $7.0 million and $19.5 million for the three and nine months ended September 30, 2011, respectively. See *Note 5*.

(3) Includes affiliate (as defined in *Note 1)* interest expense of $0.1 million and $2.7 million for the three and nine months ended September 30, 2012, respectively, and $1.2 million and $3.7 million for the three and nine months ended September 30, 2011, 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 Note 4.

(5) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. See *Note 4*.

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, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	**$ 47,494**	$ 226,559
Accounts receivable, net	**21,359**	22,703
Other current assets [(1)]	**9,386**	7,186
Total current assets	**78,239**	256,448
Note receivable Anadarko	**260,000**	260,000
Plant, property and equipment		
Cost	**3,014,825**	2,638,013
Less accumulated depreciation	**671,902**	585,789
Net property, plant and equipment	**2,342,923**	2,052,224
Goodwill	**87,936**	82,136
Other intangible assets	**52,052**	52,858
Equity investments	**105,813**	109,817
Other assets	**26,981**	24,143
Total assets	**$ 2,953,944**	$ 2,837,626
LIABILITIES, EQUITY AND PARTNERS CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [(2)]	**$ 85,992**	$ 26,600
Accrued ad valorem taxes	**15,021**	8,186
Income taxes payable	**185**	495
Accrued liabilities [(3)]	**108,883**	41,315
Total current liabilities	**210,081**	76,596
Long-term debt third parties	**1,010,435**	494,178
Note payable Anadarko		175,000
Deferred income taxes	**1,387**	107,377
Asset retirement obligations and other	**69,722**	67,169
Total long-term liabilities	**1,081,544**	843,724
Total liabilities	**1,291,625**	920,320
Equity and partners capital		
Common units (95,934,351 and 90,140,999 units issued and outstanding at September 30, 2012, and December 31, 2011, respectively)	**1,552,399**	1,495,253
General partner units (1,957,845 and 1,839,613 units issued and outstanding at September 30, 2012, and December 31, 2011, respectively)	**41,416**	31,729
Net investment by Anadarko		269,600
Total partners capital	**1,593,815**	1,796,582

Noncontrolling interests	**68,504**	120,724
Total equity and partners capital	**1,662,319**	1,917,306
Total liabilities, equity and partners capital	**$ 2,953,944**	$ 2,837,626

(1) Other current assets includes natural gas imbalance receivables from affiliates of $0.4 million and $0.5 million as of September 30, 2012, and December 31, 2011, respectively.

(2) Accounts and natural gas imbalance payables includes amounts payable to affiliates of $68.3 million and $5.9 million as of September 30, 2012, and December 31, 2011, respectively.

(3) Accrued liabilities include amounts payable to affiliates of $19.0 million and $0.3 million as of September 30, 2012, and December 31, 2011, respectively. See Note 5.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP

CONSOLIDATED STATEMENT OF EQUITY AND PARTNERS CAPITAL

(UNAUDITED)

		Partners Capital			
thousands	Net Investment by Anadarko	Common Units	General Partner Units	Noncontrolling Interests	Total
Balance at December 31, 2011	$ 269,600	$ 1,495,253	$ 31,729	$ 120,724	$ 1,917,306
Net income		105,449	18,508	11,956	135,913
Issuance of common and general partner units, net of offering expenses		211,965	4,497		216,462
Contributions from noncontrolling interest owners				26,888	26,888
Distributions to noncontrolling interest owners				(14,303)	(14,303)
Distributions to unitholders		(127,672)	(13,833)		(141,505)
Acquisition from affiliates	(482,701)	23,458	479		(458,764)
Acquisition of additional 24% interest in Chipeta [(1)]		(44,071)	162	(77,195)	(121,104)
Contributions of equity-based compensation from Anadarko		2,702	55		2,757
Net pre-acquisition contributions from (distributions to) Anadarko	106,597	(106,597)			
Net distributions of other assets to Anadarko		(10,586)	(181)	(23)	(10,790)
Elimination of net deferred tax liabilities	106,504				106,504
Non-cash equity-based compensation and other		2,498		457	2,955
Balance at September 30, 2012	**$**	**$ 1,552,399**	**$ 41,416**	**$ 68,504**	**$ 1,662,319**

(1) See *Note 2* for a description of the acquisition of Anadarko s remaining 24% membership interest in Chipeta in August 2012. The $43.9 million decrease to partners capital resulting from the August 2012 Chipeta acquisition together with net income attributable to Western Gas Partners, LP totaled $80.0 million for the nine months ended September 30, 2012.

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, 2012	2011 [(1)]
Cash flows from operating activities		
Net income	**$ 135,913**	$ 143,894
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization and impairments	**81,270**	78,413
Deferred income taxes	**514**	4,682
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	**4,931**	(17,161)
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	**71,420**	30,359
Change in other items, net	**752**	3,214
Net cash provided by operating activities	**294,800**	243,401
Cash flows from investing activities		
Capital expenditures	**(294,596)**	(78,573)
Acquisitions from affiliates	**(605,960)**	(25,000)
Acquisitions from third parties		(301,957)
Investments in equity affiliates	**(147)**	(93)
Proceeds from sale of assets to affiliates	**760**	382
Net cash used in investing activities	**(899,943)**	(405,241)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	**885,291**	1,055,939
Repayments of debt	**(549,000)**	(869,000)
Proceeds from issuance of common and general partner units, net of offering expenses	**216,462**	335,348
Distributions to unitholders	**(141,505)**	(99,795)
Contributions from noncontrolling interest owners	**26,888**	16,876
Distributions to noncontrolling interest owners	**(14,303)**	(10,219)
Net contributions from (distributions to) Anadarko	**2,245**	(42,926)
Net cash provided by financing activities	**426,078**	386,223
Net increase (decrease) in cash and cash equivalents	**(179,065)**	224,383
Cash and cash equivalents at beginning of period	**226,559**	27,074
Cash and cash equivalents at end of period	**$ 47,494**	$ 251,457
Supplemental disclosures		
Elimination of net deferred tax liabilities	**$ 106,504**	$ 22,072
Transfer of Brasada and Lancaster capital expenditures	**$ 19,197**	$
Net distributions to (contributions from) Anadarko of other assets	**$ 10,790**	$ (66)
Increase (decrease) in accrued capital expenditures	**$ 43,265**	$ 9,650
Interest paid, net of capitalized interest	**$ 16,460**	$ 9,974
Interest received	**$ 12,675**	$ 12,675
Taxes paid	**$ 495**	$ 190

(1) Financial information has been recast to include the financial position and results attributable to the MGR assets. See *Note 2*.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION

General. Western Gas Partners, LP (the Partnership), which closed its initial public offering to become publicly traded in 2008, is a growth-oriented Delaware master limited partnership formed by Anadarko Petroleum Corporation in 2007 to own, operate, acquire and develop midstream energy assets. As of September 30, 2012, the Partnership s assets included thirteen gathering systems, seven natural gas treating facilities, ten natural gas processing facilities, two NGL pipelines, one interstate gas pipeline, one intrastate gas pipeline and interests accounted for under the equity method in Fort Union Gas Gathering, LLC (Fort Union), White Cliffs Pipeline, LLC (White Cliffs) and Rendezvous Gas Services, LLC (Rendezvous). The Partnership s assets are located in East, West and South 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 for third-party producers and customers.

For purposes of these consolidated financial statements, the Partnership refers to Western Gas Partners, LP and its 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 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, White Cliffs and Rendezvous. Equity investment throughput refers to the Partnership s 14.81% share of Fort Union and 22% share of Rendezvous gross volumes, and excludes the Partnership s 10% share of White Cliffs pipeline volumes.

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, with all significant intercompany transactions eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership proportionately consolidates its 50% share of the assets, liabilities, revenues and expenses attributable to the Newcastle system in the accompanying consolidated financial statements.

In July 2009, the Partnership acquired a 51% interest in Chipeta Processing LLC (Chipeta) and became party to Chipeta s limited liability company agreement. On August 1, 2012, the Partnership closed on the acquisition of Anadarko s remaining 24% membership interest in Chipeta. Prior to this transaction, the interests in Chipeta held by Anadarko and a third-party member were reflected as noncontrolling interests in the Partnership s consolidated financial statements. The acquisition of Anadarko s remaining 24% interest was accounted for on a prospective basis as the Partnership acquired an additional interest in an already-consolidated entity. As such, beginning August 1, 2012, the Partnership s consolidated financial statements reflect its total membership interest in Chipeta of 75%. The 25% membership interest held by the third-party member is reflected as noncontrolling interests in the Partnership s consolidated financial statements for all periods presented. See *Note 2*.

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, 2012, and December 31, 2011, results of operations for the three and nine months ended September 30, 2012 and 2011, statement of equity and partners capital for the nine months ended September 30, 2012, and statements of cash flows for the nine months ended September 30, 2012 and 2011. The Partnership s financial results for the three and nine months ended September 30, 2012, are not necessarily indicative of the expected results for the full year ending December 31, 2012.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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

Presentation of Partnership assets. References to the Partnership assets refer collectively to the assets owned by the Partnership as of September 30, 2012. Because Anadarko controls the Partnership through its ownership and control of the general partner, the Partnership s acquisition of assets from Anadarko was considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko s historic carrying value, which does not correlate to the total acquisition price paid by the Partnership. Further, the Partnership may be required to recast its financial statements to include the activities of the newly acquired commonly controlled assets as of the date of common control. See *Note 2*.

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. 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 or subordinated unit.

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. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision become known.

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 2011 Form 10-K, as filed with the SEC on February 28, 2012, certain sections of which have been recast to reflect the results of the MGR assets (as defined in *Note 2*) in the Partnership s Current Report on Form 8-K, as filed with the SEC on May 22, 2012. 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.

Recently adopted accounting standard. In May 2011, the Financial Accounting Standards Board (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 and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU is to be applied prospectively and is effective for periods beginning after December 15, 2011. The Partnership adopted the ASU effective January 1, 2012. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on the Partnership s results of operations or financial position.

WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

2. ACQUISITIONS

The following table presents the acquisitions completed by the Partnership during 2012 and 2011, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued	GP Units Issued
Platte Valley [(1)]	02/28/11	100%	$ 303,000	$ 602		
Bison [(2)]	07/08/11	100%		25,000	2,950,284	60,210
MGR [(3)]	**01/13/12**	**100%**	**299,000**	**159,587**	**632,783**	**12,914**
Chipeta [(4)]	**08/01/12**	**24%**		**128,250**	**151,235**	**3,086**

(1) 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. An adjustment to intangible assets of $1.6 million was recorded in August 2011, representing the final allocation of the purchase price.

(2) The Bison gas treating facility acquired from Anadarko is located in the Powder River Basin in northeastern Wyoming and includes (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. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

(3) Mountain Gas Resources LLC (MGR), acquired from Anadarko, owns (i) the Red Desert Complex, located in the greater Green River Basin in southwestern Wyoming, including the Patrick Draw processing plant, the Red Desert processing plant, gathering lines, and related facilities, (ii) a 22% interest in Rendezvous, which owns a gathering system serving the Jonah and Pinedale Anticline fields in southwestern Wyoming, and (iii) certain additional midstream assets and equipment. These assets are collectively referred to as the MGR assets and the acquisition as the MGR acquisition. See further information below.

(4) On August 1, 2012, the Partnership acquired Anadarko s remaining 24% membership interest in Chipeta (as described in *Note 1*), with the Partnership receiving distributions related to the additional interest beginning July 1, 2012, bringing the Partnership s total membership interest in Chipeta to 75%. The 25% membership interest held by a third party is reflected as noncontrolling interests in the Partnership s consolidated financial statements for all periods presented.

Platte Valley acquisition. The Platte Valley acquisition was accounted for under the acquisition method of accounting, whereby the Platte Valley assets and liabilities were recorded in the consolidated balance sheet at their estimated fair value 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 intangible asset balance in the Partnership s consolidated balance sheets represents the fair value, net of amortization, related to the contracts assumed by the Partnership in connection with the Platte Valley acquisition in February 2011, which dedicate certain customers field production to the acquired gathering and processing system.

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

thousands except per-unit amount	Nine Months Ended September 30, 2011

Revenues	$	**624,107**
Net income		**146,620**
Net income attributable to Western Gas Partners, LP		**136,955**
Net income per common unit basic and diluted	$	**1.35**

MGR acquisition. As a transfer of net assets between entities under common control, the Partnership s historical financial statements previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the MGR 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.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

2. ACQUISITIONS (CONTINUED)

The following table presents the impact to the historical consolidated statements of income attributable to the MGR assets, including the elimination of intercompany activity between such assets:

	Three Months Ended September 30, 2011			
thousands	**Partnership Historical**	**MGR Assets**	**Eliminations**	**Combined**
Revenues	$ 175,863	$ 41,797	$ (114)	$ 217,546
Net income	40,682	8,497		49,179

	Nine Months Ended September 30, 2011			
thousands	**Partnership Historical**	**MGR Assets**	**Eliminations**	**Combined**
Revenues	$ 484,510	$ 123,767	$ (209)	$ 608,068
Net income	118,178	25,716		143,894

Other assets on the Partnership s consolidated balance sheets include a receivable of $0.5 million and $0.7 million as of September 30, 2012, and December 31, 2011, respectively, recognized in conjunction with the capital lease component of a processing agreement assumed in connection with the MGR acquisition. The agreement, in which the Partnership is the lessor, extends through December 2014. For all periods presented, other assets also include $4.6 million related to the unguaranteed residual value of the processing plant included in the processing agreement, based on a measurement of fair value estimated when the plant was acquired by Anadarko in 2006. Interest income related to the capital lease is recorded to other income (expense), net on the accompanying consolidated statements of income.

3. PARTNERSHIP DISTRIBUTIONS

The partnership agreement of Western Gas Partners, LP 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**
2011			
March 31	$ 0.390	$ 33,168	May 2011
June 30	$ 0.405	$ 36,063	August 2011
September 30	$ 0.420	$ 40,323	November 2011
2012			
March 31	**$ 0.460**	**$ 46,053**	**May 2012**
June 30	**$ 0.480**	**$ 52,425**	**August 2012**
September 30 (1)	**$ 0.500**	**$ 56,346**	**November 2012**

(1) On October 11, 2012, the board of directors of the Partnership s general partner declared a cash distribution to the Partnership s unitholders of $0.50 per unit, or $56.3 million in aggregate, including incentive distributions. The cash distribution is payable on November 13, 2012, to unitholders of record at the close of business on October 31, 2012.

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4. EQUITY AND PARTNERS CAPITAL

Equity offerings. The Partnership completed the following public offerings of its common units during 2011 and 2012:

thousands except unit and per-unit amounts	Common Units Issued [1]	GP Units Issued [2]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
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	7,655	202,748
June 2012 equity offering	**5,000,000**	**102,041**	**43.88**	**7,435**	**216,442**

[1] Includes the issuance of 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 March 2011 and September 2011 equity offerings, respectively.

[2] Represents general partner units issued to the general partner in exchange for the general partner s proportionate capital contribution to maintain its 2.0% general partner interest.

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 and general partner units issued during the nine months ended September 30, 2012:

	Common Units	General Partner Units	Total
Balance at December 31, 2011	90,140,999	1,839,613	91,980,612
MGR acquisition	**632,783**	**12,914**	**645,697**
Long-Term Incentive Plan awards	**9,334**	**191**	**9,525**
June 2012 equity offering	**5,000,000**	**102,041**	**5,102,041**
Chipeta acquisition	**151,235**	**3,086**	**154,321**
Balance at September 30, 2012	**95,934,351**	**1,957,845**	**97,892,196**

Conversion of subordinated units. Upon payment of the cash distribution for the second quarter of 2011, the requirements for the conversion of all subordinated units were satisfied under the partnership agreement. 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.

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4. EQUITY AND PARTNERS CAPITAL (CONTINUED)

Anadarko holdings of Partnership equity. As of September 30, 2012, Anadarko indirectly held 1,957,845 general partner units representing a 2.0% general partner interest in the Partnership, 40,573,239 common units representing a 41.4% limited partner interest, and 100% of the Partnership s incentive distribution rights. The public held 55,361,112 common units, representing a 56.6% limited partner interest in the Partnership.

The Partnership s net income for periods including and subsequent to the acquisition of the Partnership assets (as defined in *Note 2)* is allocated to the general partner and the limited partners 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 and the limited partners in accordance with their respective ownership percentages (see *Note 1*).

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 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	**2012**	**2011**	**2012**	**2011**
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229
Pre-acquisition net (income) loss allocated to Anadarko		(8,497)		(28,497)
General partner interest in net (income) loss	**(8,042)**	(2,394)	**(18,508)**	(5,684)
Limited partners interest in net income	**$ 31,475**	$ 34,415	**$ 105,449**	$ 100,048
Net income allocable to common units	**$ 31,475**	$ 34,415	**$ 105,449**	$ 79,030
Net income allocable to subordinated units				21,018
Limited partners interest in net income	**$ 31,475**	$ 34,415	**$ 105,449**	$ 100,048
Net income per unit basic and diluted				
Common units	**$ 0.33**	$ 0.41	**$ 1.14**	$ 1.32
Subordinated units	**$**	$	**$**	$ 0.96
Weighted average units outstanding basic and diluted				
Common units	**95,883**	84,667	**92,627**	59,647
Subordinated units				21,968

5. 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, 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 is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership s omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 2 for further information related to contributions of assets to the Partnership by Anadarko.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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 Partnership assets, 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 net investment by Anadarko in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of Partnership assets from Anadarko, transactions related to such assets are cash settled directly with third parties and with Anadarko affiliates, and affiliate-based interest expense on current intercompany balances is not charged. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.

Note receivable from and amounts payable to 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%, payable quarterly. The fair value of the note receivable from Anadarko was approximately $326.7 million and $303.7 million at September 30, 2012, and December 31, 2011, 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. Accordingly, the fair value of the note receivable from Anadarko is measured using Level 2 inputs.

In addition, in December 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko, which was repaid in full in June 2012 using the proceeds from the 4.000% Senior Notes due 2022 (the 2022 Notes). See *Note 7.*

During the first quarter of 2012, the board of directors of the Partnership s general partner approved the continued construction by the Partnership of the Brasada and Lancaster gas processing facilities in South Texas and northeast Colorado, respectively, which were previously under construction by Anadarko. The Partnership agreed to reimburse Anadarko for $18.9 million of certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada and Lancaster plants, and $0.3 million of related capitalized interest. In February 2012, these expenditures were transferred to the Partnership and a corresponding current payable was established, which the Partnership expects to repay during the fourth quarter of 2012.

Commodity price swap agreements. The Partnership has 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 commodity price 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 Granger, Hilight, Hugoton, Newcastle, MGR and Wattenberg assets, with various expiration dates through December 2016. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be re-measured at fair value. The Partnership has not entered into any new commodity price swap agreements since the fourth quarter of 2011.

Below is a summary of the fixed price ranges on the Partnership s outstanding commodity price swap agreements as of September 30, 2012:

	Year Ended December 31,								
per barrel except natural gas	**2012**		**2013**		**2014**		**2015**		**2016**
Ethane	$ 18.21	29.78	$ 18.32	30.10	$ 18.36	30.53	$ 18.41	23.41	$ 23.11
Propane	$ 45.23	57.97	$ 45.90	55.84	$ 46.47	53.78	$ 47.08	52.99	$ 52.90
Isobutane	$ 57.50	80.98	$ 60.44	77.66	$ 61.24	75.13	$ 62.09	74.02	$ 73.89
Normal butane	$ 52.40	71.15	$ 53.20	68.24	$ 53.89	66.01	$ 54.62	65.04	$ 64.93
Natural gasoline	$ 69.77	89.51	$ 70.89	92.23	$ 71.85	83.04	$ 72.88	81.82	$ 81.68

Condensate	$ 72.73	89.51	$ 74.04	85.84	$ 75.22	83.04	$ 76.47	81.82	$ 81.68
Natural gas (per MMbtu)	$ 3.62	5.97	$ 3.75	6.09	$ 4.45	6.20	$ 4.66	5.96	$ 4.87

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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

thousands	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Gains (losses) on commodity price swap agreements related to sales: (1)				
Natural gas sales	**$ 9,132**	$ 8,279	**$ 30,728**	$ 24,079
Natural gas liquids sales	**25,986**	(9,218)	**46,020**	(25,736)
Total	**35,118**	(939)	**76,748**	(1,657)
Losses on commodity price swap agreements related to purchases (2)	**(25,803)**	(6,501)	**(70,342)**	(19,377)
Net gains (losses) on commodity price swap agreements	**$ 9,315**	$ (7,440)	**$ 6,406**	$ (21,034)

(1) Reported in affiliate natural gas, NGLs and condensate sales in the Partnership s consolidated statements of income in the period in which the related sale is recorded.

(2) Reported in cost of product in the Partnership s consolidated statements of income in the period in which the related purchase is recorded.

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 76% and 78% of the Partnership s gathering, transportation and treating throughput (excluding equity investment throughput) for the three months ended September 30, 2012 and 2011, respectively, and 76% and 75% for the nine months ended September 30, 2012 and 2011, respectively, was attributable to natural gas production owned or controlled by Anadarko. Approximately 61% and 63% of the Partnership s processing throughput (excluding equity investment throughput) for the three months ended September 30, 2012 and 2011, respectively, and 59% and 64% for the nine months ended September 30, 2012 and 2011, respectively, was attributable to natural gas production owned or controlled by Anadarko.

In connection with the MGR acquisition, the Partnership entered into 10-year, fee-based gathering and processing agreements with Anadarko effective December 1, 2011, for all affiliate throughput on the MGR assets.

Equity incentive plan and Anadarko incentive plans. The Partnership s general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to (i) the Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated (the Incentive Plan) and (ii) the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans).

Under the Incentive Plan, participants are granted Unit Value Rights (UVRs), Unit Appreciation Rights (UARs) and Dividend Equivalent Rights (DERs). UVRs and UARs outstanding under the Incentive Plan were collectively valued at $1,053 per unit and $634 per unit as of September 30, 2012, and December 31, 2011, respectively. The Partnership s general and administrative expense included approximately $9.4 million and $16.4 million for the three and nine months ended September 30, 2012, respectively, and $2.4 million and $6.3 million for the three and nine months ended September 30, 2011, respectively, of equity-based compensation expense allocated to the Partnership by Anadarko for grants made pursuant to the Incentive Plan and Anadarko Incentive Plans.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Equipment purchase and sale. During the three months ended September 30, 2012, the Partnership purchased equipment with a net carrying value of $5.0 million from Anadarko for $12.2 million in cash, with the difference recorded as an adjustment to partners capital. Also during the three months ended September 30, 2012, the Partnership sold pipe and equipment with a net carrying value of $0.4 million to Anadarko for $0.8 million in cash. The gain on sale was recorded as an adjustment to partner s capital. In June 2012, the Partnership purchased equipment with a net carrying value of $1.2 million from Anadarko for $2.2 million in cash, with the difference recorded as an adjustment to partners capital. In March 2012, the Partnership purchased equipment with a net carrying value of $0.6 million from Anadarko for $4.5 million in cash, with the difference recorded as an adjustment to partners capital.

Capital expenditures transfer. As described in *Note receivable from and amounts payable to Anadarko* above, during 2011 Anadarko incurred certain expenditures related to the construction of the Brasada and Lancaster gas processing facilities, which were transferred to the Partnership in the first quarter of 2012 and are included in the balance of property, plant and equipment as of September 30, 2012. See *Note 6*.

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 Anadarko, its affiliates and the general partner:

thousands	**Three Months Ended September 30, 2012**	**2011**	**Nine Months Ended September 30, 2012**	**2011**
Revenues [(1)]	**$ 176,676**	$ 175,051	**$ 507,473**	$ 481,281
Cost of product [(1)]	**42,839**	22,774	**115,603**	59,682
Operation and maintenance [(2)]	**12,638**	13,627	**38,040**	38,692
General and administrative [(3)]	**13,742**	6,958	**29,421**	19,473
Operating expenses	**69,219**	43,359	**183,064**	117,847
Interest income, net [(4)]	**4,225**	8,573	**12,675**	18,992
Interest expense [(5)]	**81**	1,234	**2,684**	3,701
Distributions to unitholders [(6)]	**25,852**	18,000	**69,615**	48,864
Contributions from noncontrolling interest owners	**2,148**	4,647	**12,588**	8,266
Distributions to noncontrolling interest owners	**1,464**	1,335	**6,528**	5,882

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

(2) Represents expenses incurred under the services and secondment agreement for periods including and subsequent to the date of the Partnership s acquisition of the Partnership assets, as well as expenses incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets by the Partnership.

(3)

Represents general and administrative expense incurred under the omnibus agreement for periods including and subsequent to the date of the Partnership s acquisition of the Partnership assets, as well as a management services fee not within the scope of the omnibus agreement for reimbursement of expenses incurred by Anadarko for periods prior to the acquisition of the Partnership assets by the Partnership.

(4) Represents interest income recognized on the note receivable from Anadarko. This line item also includes interest income, net on affiliate balances related to the Bison and MGR assets for periods prior to the acquisition of such assets. Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on the Bison and MGR assets prior to their acquisition were entirely settled through an adjustment to net investment by Anadarko.

(5) Represents interest expense recognized on the note payable to Anadarko (see Note 7) and interest imputed on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada and Lancaster plants (see Note receivable from and amounts payable to Anadarko within this Note 5). In June 2012, the note payable to Anadarko was repaid in full.

(6) Represents distributions paid under the partnership agreement.

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.

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6. PROPERTY, PLANT AND EQUIPMENT

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

thousands	Estimated Useful Life	September 30, 2012	December 31, 2011
Land	n/a	**$ 501**	$ 364
Gathering systems	5 to 47 years	**2,529,475**	2,437,152
Pipelines and equipment	15 to 45 years	**91,126**	90,883
Assets under construction	n/a	**387,026**	104,687
Other	3 to 25 years	**6,697**	4,927
Total property, plant and equipment		**3,014,825**	2,638,013
Accumulated depreciation		**671,902**	585,789
Net property, plant and equipment		**$ 2,342,923**	$ 2,052,224

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. Assets under construction includes $18.9 million related to the transfer of the Brasada and Lancaster gas processing facilities (see Note 5), and $0.3 million of related capitalized interest. In addition, property, plant and equipment cost and third-party accrued liability balances in the Partnership s consolidated balance sheets each include $58.2 million and $15.0 million of accrued capital as of September 30, 2012, and December 31, 2011, respectively, representing estimated capital expenditures for which invoices had not yet been processed.

7. DEBT AND INTEREST EXPENSE

The following table presents the Partnership s outstanding debt as of September 30, 2012, and December 31, 2011:

	September 30, 2012			December 31, 2011		
thousands	Principal	Carrying Value	Fair Value	Principal	Carrying Value	Fair Value
4.000% Senior Notes due 2022	**$ 520,000**	**$ 515,897**	**$ 519,728**	$	$	$
5.375% Senior Notes due 2021	**500,000**	**494,538**	**499,950**	500,000	494,178	499,950
Note payable to Anadarko				175,000	175,000	174,528
Total debt outstanding (1)	**$ 1,020,000**	**$ 1,010,435**	**$ 1,019,678**	$ 675,000	$ 669,178	$ 674,478

(1) The Partnership s consolidated balance sheets include accrued interest expense of $14.3 million and $2.7 million as of September 30, 2012, and December 31, 2011, 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 the 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. Accordingly, the fair value of the debt instruments in the table above is measured using Level 2 inputs.

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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, 2012:

thousands	Carrying Value
Balance as of December 31, 2011	**$ 669,178**
Revolving credit facility borrowings	**374,000**
Issuance of 4.000% Senior Notes due 2022	**520,000**
Repayment of revolving credit facility	**(374,000)**
Repayment of Note payable to Anadarko	**(175,000)**
Revolving credit facility borrowings Swingline	**20,000**
Repayment of revolving credit facility Swingline	**(20,000)**
Other and changes in debt discount	**(3,743)**
Balance as of September 30, 2012	**$ 1,010,435**

4.000% Senior Notes due 2022. In June 2012, the Partnership completed the offering of $520.0 million aggregate principal amount of the 2022 Notes at a price to the public of 99.194% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate is 4.207%. Interest will be paid semi-annually on January 1 and July 1 of each year, commencing on January 1, 2013. The 2022 Notes will mature on July 1, 2022, unless redeemed, in whole or in part, at any time prior to maturity, at a redemption price that includes a make-whole premium. Proceeds (net of underwriting discount of $3.4 million and debt issuance costs) were used to repay all amounts then outstanding under the Partnership s revolving credit facility (RCF) and the $175.0 million note payable to Anadarko (see below).

The 2022 Notes indenture contains customary events of default including, among others, (i) default for 30 days in the payment of interest when due on the 2022 Notes; (ii) default in payment, when due, of principal of or premium, if any, on the 2022 Notes at maturity, upon redemption or otherwise; and (iii) certain events of bankruptcy or insolvency. The 2022 Notes indenture also contains covenants that limit, among other things, the Partnership s ability, as well as that of certain of its subsidiaries, to (i) create liens on its 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 its properties or assets to another entity. At September 30, 2012, the Partnership was in compliance with all covenants under the 2022 Notes.

Refer to *Note 9* for a discussion of the additional offering of the 2022 Notes in October 2012.

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 2021 Notes) at a price to the public of 98.778% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate is 5.648%.

Upon issuance, the 2021 Notes were 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 were immediately released on June 13, 2012, upon the Subsidiary Guarantors becoming released from their obligations under the RCF, as discussed below. At September 30, 2012, the Partnership was in compliance with all covenants under the 2021 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 term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity in 2013. In June 2012, the note payable to Anadarko was repaid in full with proceeds from the issuance of the 2022 Notes.

Revolving credit facility. In March 2011, the Partnership entered into an amended and restated $800.0 million senior unsecured RCF which matures in March 2016 and bears interest at London Interbank Offered Rate (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%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from 0.30% to 0.90%. The interest rate was 1.71% and 1.80% at September 30, 2012, and December 31, 2011, 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% at September 30, 2012, and December 31, 2011.

On June 13, 2012, following the receipt of a second investment grade rating as defined in the RCF, the guarantees provided by the Partnership s wholly owned subsidiaries were released, and the Partnership is no longer subject to certain of the restrictive covenants associated with the RCF, including the maintenance of an interest coverage ratio and adherence to covenants that limit, among other things, the Partnership s, and certain of the Partnership s subsidiaries , ability to dispose of assets and make certain investments or payments. The Partnership did not have outstanding borrowings under its $800.0 million RCF as of September 30, 2012, and had $0.3 million in outstanding letters of credit issued under the facility. At September 30, 2012, the Partnership was in compliance with all remaining covenants under the RCF.

The 2022 Notes, the 2021 Notes and obligations under the RCF are recourse to the Partnership s general partner. In turn, the Partnership s general partner has been indemnified by a wholly owned subsidiary of Anadarko against any claims made against the general partner under the 2022 Notes, the 2021 Notes and/or the RCF.

Wattenberg term loan. The Partnership repaid the $250.0 million Wattenberg term loan in full in March 2011 using borrowings from its RCF and recognized $1.3 million of accelerated amortization expense related to its early repayment.

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7. DEBT AND INTEREST EXPENSE (CONTINUED)

Interest rate agreements. In May 2012, the Partnership entered into U.S. Treasury Rate lock agreements to mitigate the risk of rising interest rates prior to the issuance of the 2022 Notes. The rate lock agreements were settled simultaneously with the issuance of the 2022 Notes in June 2012, realizing a loss of $1.7 million, which is included in other income (expense), net in the Partnership s consolidated statements of income.

In March 2011, the Partnership entered into a forward-starting interest-rate swap agreement to mitigate the risk of rising interest rates prior to the issuance of the 2021 Notes. In May 2011, the Partnership issued the 2021 Notes and terminated the swap agreement, realizing a loss of $1.9 million, which is included in other income (expense), net in the Partnership s consolidated statements of income.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	**2012**	**2011**	**2012**	**2011**
Third parties				
Interest expense on long-term debt	**$ 11,919**	$ 6,739	**$ 28,036**	$ 13,889
Amortization of debt issuance costs and commitment fees [(1)]	**1,201**	1,078	**3,225**	4,282
Capitalized interest	**(2,224)**	(121)	**(3,827)**	(134)
Total interest expense third parties	**10,896**	7,696	**27,434**	18,037
Affiliates				
Interest expense on note payable to Anadarko [(2)]		1,234	**2,440**	3,701
Interest expense on affiliate balances [(3)]	**81**		**244**	
Total interest expense affiliates	**81**	1,234	**2,684**	3,701
Interest expense	**$ 10,977**	$ 8,930	**$ 30,118**	$ 21,738

(1) Amortization of the original issue discount and underwriters fees related to the 2022 Notes and 2021 Notes was $0.4 million and $0.8 million for the three and nine months ended September 30, 2012, respectively, and related to the 2021 Notes was $0.2 million and $0.3 million for the three and nine months ended September 30, 2011, respectively.

(2) In June 2012, the note payable to Anadarko was repaid in full. See *Note payable to Anadarko* within this *Note 7*.

(3) Imputed interest expense on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada and Lancaster plants. See *Note 5*.

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(UNAUDITED)

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. Anadarko countersued DCP asserting that DCP has not properly allocated values and charges to Anadarko for the gas that DCP gathers and/or processes, and seeks a judgment that DCP has no valid gathering or processing rights to much of the gas production it is claiming, in addition to other claims. In July 2011, the Court denied the defendants motion to dismiss without ruling on the merits and the case is in the discovery phase. Trial is set for April 2014. 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.

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates. As of September 30, 2012, the Partnership had unconditional payment obligations for services to be rendered, or products to be delivered in connection with its capital projects of approximately $78.8 million, which includes 100% of obligations related to Chipeta. A majority of these payment obligations will be paid in the next twelve months, and relate primarily to the continued construction of the Brasada and Lancaster plants (see *Note 5*) and capital projects at Chipeta.

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 February 2014 and includes an early termination clause. During 2011, Anadarko entered into a lease agreement for the Partnership s corporate offices that extends through March 2017. Anadarko, on behalf of the Partnership, continues to lease certain other compression equipment under leases expiring through January 2015.

Rent expense associated with the office, warehouse and equipment leases was $0.8 million and $2.3 million for the three and nine months ended September 30, 2012, respectively, and $1.1 million and $3.1 million for the three and nine months ended September 30, 2011, respectively.

9. SUBSEQUENT EVENT

In October 2012, the Partnership issued an additional $150.0 million in aggregate principal amount of 4.000% Senior Notes due 2022 (the New Notes), at a price to the public of 105.178% of the face amount. The New Notes were offered as additional notes under the indenture governing the 2022 Notes issued in June 2012 (described in *Note 7*) and are treated as a single class of securities with the 2022 Notes under such indenture. Interest on the New Notes accrues from June 28, 2012, the date the 2022 Notes were issued, and will be payable semi-annually in arrears on January 1 and July 1 of each year, commencing January 1, 2013. Including the effects of the issuance premium and underwriting fees, the effective interest rate of the New Notes is 3.527%. Proceeds from issuance of the New Notes (net of underwriting fees of $1.0 million and debt issuance costs) will be used for general partnership purposes, which may include the funding of capital expenditures.

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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 have been recast to reflect the results of the acquisition of Mountain Gas Resources, LLC in our Current Report on Form 8-K, as filed with the Securities and Exchange Commission, or SEC, on May 22, 2012), and other public filings and press releases by Western Gas Partners, LP. Unless the context otherwise requires, references to we, us, our, the Partnership or Western Gas Partners refers to Western Gas Partners, LP and its subsidiaries, including the financial results of the Partnership assets (described below) from their respective date acquired by entities under common control, for all periods presented. For ease of reference, we also refer to the historical financial results of the Partnership assets prior to our acquisitions as being our historical financial results. Anadarko refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and our 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 Anadarko and its wholly owned and partially owned subsidiaries, excluding the Partnership, and also refers to Fort Union Gas Gathering, LLC, or Fort Union, White Cliffs Pipeline, LLC, or White Cliffs, and Rendezvous Gas Services, LLC, or Rendezvous. References to the Partnership assets refer collectively to the assets owned by the Partnership as of September 30, 2012.

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 sim These statements discuss 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, the demand for, and the prices of, oil, natural gas, NGLs and related products or services;
- the weather;

inflation;

the availability of goods and services, including downstream transportation and fractionation capacity;

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- general economic conditions, either internationally or nationally or in the jurisdictions in which we are doing business;
- changes in environmental and safety regulations; environmental risks; regulations by the Federal Energy Regulatory Commission (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 and the ability to complete such projects on time and within budget expectations;
- the ability to utilize our revolving credit facility (RCF);
- 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;
- the timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below, in Risk Factors included in our 2011 Form 10-K, in Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates included in our Current Report on Form 8-K filed May 22, 2012, in our quarterly reports on Form 10-Q and elsewhere 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. 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 Delaware master limited partnership (MLP) organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently own assets located in East, West and South Texas, the Rocky Mountains (Colorado, Utah and Wyoming), and the Mid-Continent (Kansas and Oklahoma) and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko and its consolidated subsidiaries, as well as for third-party producers and customers. As of September 30, 2012, our assets consisted of thirteen gathering systems, seven natural gas treating facilities, ten natural gas processing facilities, two NGL pipelines, one interstate gas pipeline, one intrastate gas pipeline and interests accounted for under the equity method in two gas gathering systems and a crude oil pipeline.

Significant financial highlights during the first nine months of 2012 include the following:

- We issued $520.0 million aggregate principal amount of 4.000% Senior Notes due 2022 (the 2022 Notes). Net proceeds from this issuance were used to repay all amounts then outstanding under our revolving credit facility and the note payable to Anadarko, with the remaining net proceeds used for general partnership purposes. See *Liquidity and Capital Resources* below.

- We issued 5,000,000 common units to the public, generating net proceeds of $216.6 million, including the general partner s proportionate capital contribution to maintain its 2.0% general partner interest. Net proceeds are being used for general partnership purposes, including the funding of capital expenditures. See *Equity Offerings* below.

- We completed the acquisition of Anadarko s MGR assets located in southwestern Wyoming in January and the acquisition of Anadarko s remaining 24% interest in Chipeta in August. See *Acquisitions* below.

- We announced two growth projects: (i) the expansion of our processing capacity by 300 MMcf/d at our Wattenberg system with the construction of the Lancaster plant, and (ii) the construction of a new 200 MMcf/d cryogenic processing plant in the Maverick Basin, referred to as the Brasada plant. Startup is anticipated in the first quarter of 2014 for the Lancaster plant and the second quarter of 2013 for the Brasada plant. See *Liquidity and Capital Resources* below.

- We raised our distribution to $0.50 per unit for the third quarter of 2012, representing a 4% increase over the distribution for the second quarter of 2012, a 19% increase over the distribution for the third quarter of 2011, and our fourteenth consecutive quarterly increase.

Significant operational highlights during the first nine months of 2012 include the following:

- Throughput attributable to Western Gas Partners, LP totaled 2,461 MMcf/d and 2,419 MMcf/d for the three and nine months ended September 30, 2012, respectively, representing a 10% and 9% increase, respectively, compared to the same periods in 2011.

- Gross margin (total revenues less cost of product) attributable to Western Gas Partners, LP averaged $0.55 per Mcf for both the three and nine months ended September 30, 2012, representing a 7% and 5% decrease, respectively, compared to the same periods in 2011.

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ACQUISITIONS

Acquisitions. The following table presents our acquisitions completed during 2012 and 2011, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued	GP Units Issued
Platte Valley [(1)]	02/28/11	100%	$ 303,000	$ 602		
Bison [(2)]	07/08/11	100%		25,000	2,950,284	60,210
MGR [(3)]	**01/13/12**	**100%**	**299,000**	**159,587**	**632,783**	**12,914**
Chipeta [(4)]	**08/01/12**	**24%**		**128,250**	**151,235**	**3,086**

(1) The assets acquired from a third party include (i) a processing plant with initial cryogenic capacity of 84 MMcf/d, (ii) two fractionation trains, (iii) an initial 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. An adjustment to intangible assets of $1.6 million was recorded in August 2011, representing the final allocation of the purchase price. 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 RCF. See *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

(2) The Bison gas treating facility that we acquired from Anadarko is located in the Powder River Basin in northeastern Wyoming, and includes (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. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

(3) Mountain Gas Resources LLC (MGR), acquired from Anadarko, owns (i) the Red Desert Complex, located in the greater Green River Basin in southwestern Wyoming, including the Patrick Draw processing plant with a capacity of 125 MMcf/d, the Red Desert processing plant with a capacity of 48 MMcf/d, 1,295 miles of gathering lines, and related facilities, (ii) a 22% interest in Rendezvous, which owns a 338-mile mainline gathering system serving the Jonah and Pinedale Anticline fields in southwestern Wyoming, and (iii) certain additional midstream assets and equipment. These assets are collectively referred to as the MGR assets and the acquisition as the MGR acquisition. In connection with the MGR acquisition, we entered into 10-year, fee-based gathering and processing agreements with Anadarko effective December 1, 2011, for all affiliate throughput on the MGR assets.

(4) On August 1, 2012, we acquired Anadarko s remaining 24% membership interest in Chipeta (as described in *Note 1 Description of Business and Basis of Presentation* under Item 1 of this Form 10-Q), with the Partnership receiving distributions related to the additional interest beginning July 1, 2012, bringing our total membership interest in Chipeta to 75%. The 25% held by a third-party member is reflected as noncontrolling interests in our consolidated financial statements for all periods presented.

Presentation of Partnership assets. References to the Partnership assets refer collectively to the assets owned by us as of September 30, 2012. Because Anadarko controls us through its ownership and control of our general partner, our acquisition of assets from Anadarko was considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko s historic carrying value, which does not correlate to the total acquisition price paid by us (see *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q). Further, we may be required to recast our financial statements to include the activities of the newly acquired commonly controlled assets as of the date of common control.

The historical financial statements previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the MGR 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 from Anadarko 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.

EQUITY OFFERINGS

Equity offerings. We completed the following public offerings of our common units during 2011 and 2012:

thousands except unit and per-unit amounts	Common Units Issued [(1)]	GP Units Issued [(2)]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
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	7,655	202,748
June 2012 equity offering	**5,000,000**	**102,041**	**43.88**	**7,435**	**216,442**

(1) Includes the issuance of 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 March 2011 and September 2011 equity offerings, respectively.

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

In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to $125.0 million of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of September 30, 2012, we had not issued any common units under this registration statement.

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RESULTS OF OPERATIONS

OPERATING RESULTS

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

thousands	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 78,219**	$ 75,686	**$ 235,849**	$ 222,432
Natural gas, natural gas liquids and condensate sales	**136,106**	137,860	**386,818**	371,800
Equity income and other, net	**4,695**	4,000	**13,936**	13,836
Total revenues [1]	**219,020**	217,546	**636,603**	608,068
Total operating expenses [1]	**169,778**	163,600	**482,261**	444,969
Operating income	**49,242**	53,946	**154,342**	163,099
Interest income, net affiliates	**4,225**	8,573	**12,675**	18,992
Interest expense	**(10,977)**	(8,930)	**(30,118)**	(21,738)
Other income (expense), net	**522**	258	**(287)**	(895)
Income before income taxes	**43,012**	53,847	**136,612**	159,458
Income tax expense	**72**	4,668	**699**	15,564
Net income	**42,940**	49,179	**135,913**	143,894
Net income attributable to noncontrolling interests	**3,423**	3,873	**11,956**	9,665
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229
Key Performance Metrics [2]				
Gross margin	**$ 129,913**	$ 127,880	**$ 381,884**	$ 367,303
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 84,497**	$ 82,256	**$ 244,349**	$ 241,284
Distributable cash flow	**$ 64,360**	$ 66,934	**$ 197,285**	$ 211,313

(1) Revenues include amounts earned from services provided to our affiliates, as well as from the sale of residue, 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 5 Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under 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 *Key Performance Metrics* 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 in the United States (GAAP).

For purposes of the following discussion, any increases or decreases for the three months ended September 30, 2012 refer to the comparison of the three months ended September 30, 2012, to the three months ended September 30, 2011; any increases or decreases for the nine months ended September 30, 2012 refer to the comparison of the nine months ended September 30, 2012, to the nine months ended September 30, 2011; and any increases or decreases for the three and nine months ended September 30, 2012 refer to both the comparison for the three months ended September 30, 2012, and to the comparison for the nine months ended September 30, 2012.

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Operating Statistics

	Three Months Ended September 30,			Nine Months Ended September 30,		
throughput in MMcf/d	**2012**	**2011**	D	**2012**	**2011**	D
Gathering, treating and transportation [(1)]	**1,201**	1,274	(6)%	**1,255**	1,327	(5)%
Processing [(2)]	**1,228**	1,012	21%	**1,182**	940	26%
Equity investment [(3)]	**236**	212	11%	**236**	191	24%
Total throughput [(4)]	**2,665**	2,498	7%	**2,673**	2,458	9%
Throughput attributable to noncontrolling interests	**204**	258	(21)%	**254**	237	7%
Total throughput attributable to Western Gas Partners, LP	**2,461**	2,240	10%	**2,419**	2,221	9%

(1) Excludes average NGL pipeline volumes from the Chipeta assets of 22 MBbls/d and 25 MBbls/d for the three months ended September 30, 2012 and 2011, respectively, and 25 MBbls/d and 23 MBbls/d for the nine months ended September 30, 2012 and 2011, respectively.

(2) Consists of 100% of Chipeta, Granger, Hilight and Red Desert complex 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 and 22% share of Rendezvous gross volumes, and excludes our 10% share of average White Cliffs pipeline volumes consisting of 6 MBbls/d and 4 MBbls/d for the three months ended September 30, 2012 and 2011, respectively, and 6 MBbls/d and 3 MBbls/d for the nine months ended September 30, 2012 and 2011, respectively.

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

Gathering, treating and transportation throughput decreased by 73 MMcf/d and 72 MMcf/d for the three and nine months ended September 30, 2012, respectively, resulting from: throughput decreases at the Haley, Pinnacle, Hugoton and Dew systems resulting from natural production declines and reduced drilling activity in those areas; throughput decreases at MIGC due to the September 2012 expiration of a firm transportation agreement; and throughput decreases at the Bison facility resulting from reduced drilling activity in the area driven by unfavorable producer economics. These decreases were partially offset by a throughput increase at Wattenberg due to increased drilling behind the system.

Processing throughput increased by 216 MMcf/d and 242 MMcf/d for the three and nine months ended September 30, 2012, respectively, primarily due to: volumes processed at a plant included in the MGR acquisition under a new contract effective January 2012, with no volumes in the comparable period; throughput increases at the Chipeta system resulting from increased drilling activity; and for the nine months ended September 30, 2012, additional throughput from the Platte Valley system beginning in March 2011.

Equity investment volumes increased by 24 MMcf/d and 45 MMcf/d for the three and nine months ended September 30, 2012, respectively, resulting from higher throughput at the Fort Union system due to producers choosing to route additional gas to reach desired end markets and at the Rendezvous system due to increased third-party drilling activity.

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Natural Gas Gathering, Processing and Transportation Revenues

thousands except percentages	Three Months Ended September 30, 2012	2011	D	Nine Months Ended September 30, 2012	2011	D
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 78,219**	$ 75,686	3%	**$ 235,849**	$ 222,432	6%

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $2.5 million for the three months ended September 30, 2012, primarily due to increases of $3.6 million and $2.1 million due to increased drilling activity in the areas around the Wattenberg and Chipeta systems, respectively, and increased rates at the Haley system for an increase of $0.8 million. These increases were partially offset by decreased revenue of $1.0 million at the Helper system due to a downward rate revision effective April 1, 2012, decreased revenue of $0.5 million at the Platte Valley system due to decreased wellhead volumes and a rate adjustment, decreased revenue of $0.5 million at the Red Desert complex due to changes in contracts and lower volumes due to shut-ins, decreased revenue of $0.4 million at MIGC due to the expiration of firm transportation agreements and due to a decrease in interruptible volumes, decreased revenue of $0.3 million at a plant included in the MGR acquisition due to the expiration of processing agreements, and decreased revenue of $0.9 million due to decreased throughput at the Dew, Pinnacle and Clawson systems as a result of natural production declines in the area.

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $13.4 million for the nine months ended September 30, 2012, primarily due to increases of $8.8 million and $7.4 million due to increased drilling activity in the areas around the Wattenberg and Chipeta systems, respectively, an increase of $5.5 million due to the acquisition of the Platte Valley system in February 2011, and an increase of $2.1 million due to increased rates at the Haley system. These increases were partially offset by decreased revenue of $2.0 million at the Granger system due to diverted volumes, decreased revenue of $1.9 million at the Helper system due to a downward rate revision effective April 1, 2012, decreased revenue of $1.4 million at MIGC due to the expiration of firm transportation agreements, decreased revenue of $1.3 million at the Red Desert complex due to changes in contracts and lower volumes due to shut-ins, and decreased revenue of $3.3 million due to decreased throughput at the Pinnacle, Dew and Hugoton systems as a result of natural production declines in the area.

Natural Gas, Natural Gas Liquids and Condensate Sales

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2012	2011	D	Nine Months Ended September 30, 2012	2011	D
Natural gas sales	**$ 24,223**	$ 36,351	(33)%	**$ 73,524**	$ 98,610	(25)%
Natural gas liquids sales	**105,124**	95,602	10%	**291,293**	253,538	15%
Drip condensate sales	**6,759**	5,907	14%	**22,001**	19,652	12%
Total	**$ 136,106**	$ 137,860	(1)%	**$ 386,818**	$ 371,800	4%
Average price per unit:						
Natural gas (per Mcf)	**$ 4.21**	$ 5.43	(22)%	**$ 4.19**	$ 5.43	(23)%
Natural gas liquids (per Bbl)	**$ 49.76**	$ 49.07	1%	**$ 48.21**	$ 47.13	2%
Drip condensate (per Bbl)	**$ 76.75**	$ 73.28	5%	**$ 76.28**	$ 73.45	4%

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales decreased by $1.8 million for the three months ended September 30, 2012, which consisted of a $12.1 million decrease in natural gas sales, partially offset by a $9.5 million increase in NGLs sales and a $0.9 million increase in drip condensate sales.

For the three months ended September 30, 2012, natural gas sales decreased primarily due to a 22% lower natural gas sales price and a decrease in volumes of 14%, largely attributable to decreases of $5.1 million, $2.5 million and $1.7 million at the Hilight system, Wattenberg system and Red Desert complex, respectively, and a $2.7 million price-related decrease at the Platte Valley system.

The increase in NGLs sales was primarily due to: increases in volumes sold of $4.0 million and $1.5 million at the Chipeta and Hilight systems, respectively; a price-related increase of $5.0 million at the Red Desert complex; and an increase of $5.3 million due to volumes processed at a plant included in the MGR acquisition under a new contract effective January 2012, with no volumes in the comparable period. These increases were partially offset by a decrease at the Platte Valley system of $6.5 million due to decreases in volumes and price.

The increase in drip condensate sales was primarily a result of a $1.0 million increase at the Wattenberg system, partially offset by a decrease of $0.3 million at the Hugoton system, due to a decline in throughput.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $15.0 million for the nine months ended September 30, 2012, which consisted of a $37.8 million increase in NGLs sales and a $2.3 million increase in drip condensate sales, partially offset by a $25.1 million decrease in natural gas sales.

For the nine months ended September 30, 2012, the increase in NGLs sales was primarily due to: $15.8 million, $7.3 million, $6.8 million and $4.1 million due to increased volumes sold at the Chipeta, Granger, Hilight, and Wattenberg systems, respectively; a $2.4 million increase due to increased volumes at the Red Desert complex; and an increase of $7.6 million related to volumes processed at a plant included in the MGR acquisition under a new contract effective January 2012, with no volumes in the comparable period. These increases were partially offset by a $6.8 million price-related decrease at the Platte Valley system.

The increase in drip condensate sales for the nine months ended September 30, 2012 was primarily due to a $2.1 million increase at the Wattenberg system, and a $0.7 million increase at the Platte Valley system due to increased sales volumes and prices. These increases were partially offset by a $0.5 million decrease at the Hugoton system as a result of lower volumes.

The decrease in natural gas sales was primarily due to a 23% decrease in overall natural gas sales prices, in addition to the following decreases due to lower sales volumes: a $12.9 million decrease at the Hilight system, a $4.9 million decrease at the Red Desert complex, a $2.7 million decrease at the Wattenberg system and a $3.1 million decrease at the Platte Valley system.

The average natural gas and NGLs prices for the three and nine months ended September 30, 2012, include the effects of commodity price swap agreements attributable to sales for the Granger, Hilight, Hugoton, Newcastle and Wattenberg systems, and the MGR assets. 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, Hilight, Hugoton, Newcastle and Wattenberg systems. See *Note 5 Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

Equity Income and Other Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2012**	**2011**	D	**2012**	**2011**	D
Equity income	**$ 3,804**	$ 2,660	43%	**$ 10,752**	$ 7,682	40%
Other revenues, net	**891**	1,340	(34)%	**3,184**	6,154	(48)%
Total	**$ 4,695**	$ 4,000	17%	**$ 13,936**	$ 13,836	1%

Equity income increased by $1.1 million and $3.1 million for the three and nine months ended September 30, 2012, respectively, due to the increase in income from White Cliffs and Rendezvous as a result of increased volumes.

Other revenues decreased by $0.4 million and $3.0 million for the three and nine months ended September 30, 2012, respectively, primarily due to indemnity fees received in the prior year at the Red Desert complex and Hugoton system, with no comparable activity in the current periods.

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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	**2012**	2011	D	**2012**	2011	D
Cost of product	**$ 89,107**	$ 89,666	(1)%	**$ 254,719**	$ 240,765	6%
Operation and maintenance	**33,261**	31,773	5%	**97,041**	87,859	10%
Total cost of product and operation and maintenance expenses	**$ 122,368**	$ 121,439	1%	**$ 351,760**	$ 328,624	7%

Including the effects of commodity price swap agreements on purchases, cost of product expense decreased by $0.6 million for the three months ended September 30, 2012, primarily due to a $5.5 million decrease attributable to lower NGL and residue prices at the Platte Valley system, and a $5.3 million decrease due to declines in NGL volumes purchased and prices at the Hilight system. Partially offsetting the decrease was a $4.9 million increase due to higher NGL and residue prices for the MGR assets due to commodity price swap agreements beginning January 2012, and a $5.3 million increase attributable to increased NGL volumes purchased and prices at the Chipeta and Granger systems.

Cost of product expense increased by $14.0 million for the nine months ended September 30, 2012, primarily due to a $15.8 million increase attributable to increases in NGL volumes purchased and higher pricing at the Chipeta system, a $5.7 million increase at the Hilight system due to increased NGL volumes purchased and higher pricing, and increases of $4.8 million and $3.4 million for the MGR assets and the Granger system, respectively, related to increased residue purchases. Partially offsetting the increase was an $11.4 million decrease due to declines in residue purchases and prices at the Hilight system, and a $5.4 million decrease attributable to lower NGL and residue prices at the Platte Valley system.

Cost of product expense for the three and nine months ended September 30, 2012, includes the effects of commodity price swap agreements attributable to purchases for the Granger, Hilight, Hugoton, Newcastle and Wattenberg systems, and for the MGR assets. Cost of product expense for the three and nine months ended September 30, 2011, includes the effects of commodity price swap agreements attributable to purchases for the Granger, Hilight, Hugoton, Newcastle, and Wattenberg systems. See *Note 5 Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

Operation and maintenance expense increased by $1.5 million for the three months ended September 30, 2012, primarily due to increased maintenance expenses of $1.4 million incurred at the Wattenberg and Hilight systems and a $0.5 million increase due to the acquisition of the Platte Valley system. These increases were partially offset by $0.4 million of reduced variable operating expenses at the Red Desert complex resulting from decreased throughput activity compared to the same periods in the prior year. Operation and maintenance expense increased by $9.2 million for the nine months ended September 30, 2012, primarily due to increased maintenance expenses of $5.6 million due to the acquisition of the Platte Valley system in February 2011 and a $4.7 million increase incurred at the Wattenberg and Hilight systems. These increases were partially offset by $1.3 million of reduced variable operating expenses at the Red Desert complex resulting from decreased throughput activity compared to the same periods in the prior year.

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General and Administrative, Depreciation and Other Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2012**	**2011**	D	**2012**	**2011**	D
General and administrative	**$ 14,554**	$ 8,597	69%	**$ 34,233**	$ 24,630	39%
Property and other taxes	**5,328**	4,629	15%	**14,998**	13,302	13%
Depreciation, amortization and impairments	**27,528**	28,935	(5)%	**81,270**	78,413	4%
Total general and administrative, depreciation and other expenses	**$ 47,410**	$ 42,161	12%	**$ 130,501**	$ 116,345	12%

General and administrative expenses increased by $6.0 million for the three months ended September 30, 2012, due to an increase of $7.0 million in non-cash compensation expenses primarily due to an increase from $370 per unit to $1,053 per unit in the value of equity-based awards and an increase of $0.8 million in corporate and management personnel costs allocated to us pursuant to our omnibus agreement. These increases were partially offset by a $0.9 million decrease in management fees allocated to the Bison and MGR assets, the agreements for which were discontinued as of the respective dates of such assets contribution to us and a $0.9 million decrease in consulting and audit fees.

General and administrative expenses increased by $9.6 million for the nine months ended September 30, 2012, due to an increase of $10.1 million in non-cash compensation expenses primarily due to an increase from $370 per unit to $1,053 per unit in the value of equity-based awards and an increase of $3.1 million in corporate and management personnel costs allocated to us pursuant to our omnibus agreement. These increases were partially offset by a $3.2 million decrease in management fees allocated to the Bison and MGR assets, the agreements for which were discontinued as of the respective dates of contribution and a $0.4 million decrease in consulting and audit fees.

Property and other taxes increased by $0.7 million and $1.7 million for the three and nine months ended September 30, 2012, respectively, primarily due to ad valorem tax increases at the Platte Valley and Wattenberg assets.

Depreciation, amortization and impairments decreased by $1.4 million and increased by $2.9 million for the three and nine months ended September 30, 2012, respectively, primarily attributable to the addition of the Platte Valley assets, and depreciation associated with capital projects completed at Wattenberg, Hilight and the Red Desert complex, partially offset by a $3.0 million impairment recognized during the three months ended September 30, 2011, for a pipeline included in the MGR acquisition, with no comparable impairment during the three months ended September 30, 2012.

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Interest Income, Net Affiliates and Interest Expense

thousands except percentages	Three Months Ended September 30, 2012	2011	D	Nine Months Ended September 30, 2012	2011	D
Interest income on note receivable	**$ 4,225**	$ 4,225	%	**$ 12,675**	$ 12,675	%
Interest income, net on affiliate balances [2]		4,348	(100)%		6,317	(100)%
Interest income, net affiliates	**$ 4,225**	$ 8,573	(51)%	**$ 12,675**	$ 18,992	(33)%
Third parties						
Interest expense on long-term debt	**$ (11,919)**	$ (6,739)	77%	**$ (28,036)**	$ (13,889)	102%
Amortization of debt issuance costs and commitment fees [3]	**(1,201)**	(1,078)	11%	**(3,225)**	(4,282)	(25)%
Capitalized interest	**2,224**	121	nm [1]	**3,827**	134	nm [1]
Affiliates						
Interest expense on note payable to Anadarko [4]		(1,234)	(100)%	**(2,440)**	(3,701)	(34)%
Interest expense, net on affiliate balances	**(81)**		nm	**(244)**		nm
Interest expense	**$ (10,977)**	$ (8,930)	23%	**$ (30,118)**	$ (21,738)	39%

(1) Percent change is not meaningful (nm).
(2) Incurred on affiliate balances related to the Bison and MGR assets for periods prior to the acquisition of such assets. Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on the Bison and MGR assets prior to their acquisition were entirely settled through an adjustment to net investment by Anadarko.
(3) Amortization of the original issue discount and underwriters fees related to the 2022 Notes and 2021 Notes (as defined in *Note 7 Debt and Interest Expense*) was $0.4 million and $0.8 million for the three and nine months ended September 30, 2012, respectively, and related to the 2021 Notes was $0.2 million and $0.3 million for the three and nine months ended September 30, 2011.
(4) In June 2012, we repaid in full the note payable to Anadarko.

Interest expense increased by $2.0 million for the three months ended September 30, 2012, primarily due to interest expense incurred on the $520.0 million aggregate principal amount of 4.000% Senior Notes due 2022 (the 2022 Notes) that were issued in June 2012, partially offset by increased capitalized interest associated with the construction of a second cryogenic train at the Chipeta plant. See *Note 7 Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

Interest expense increased by $8.4 million for the nine months ended September 30, 2012, primarily due to interest expense incurred on the $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the 2021 Notes) that were issued in May 2011 and interest expense incurred on the 2022 Notes, partially offset by increased capitalized interest associated with the construction of a second cryogenic train at the Chipeta plant, reductions resulting from the early repayment of the Wattenberg term loan in March 2011 and the related $1.3 million of accelerated amortization expense recognized in March 2011 (described in *Liquidity and Capital Resources* below).

Other Income (Expense), Net

thousands except percentages	Three Months Ended September 30, 2012	2011	D	Nine Months Ended September 30, 2012	2011	D
Other income (expense), net	**$ 522**	$ 258	102%	**$ (287)**	$ (895)	(68)%

Other income (expense), net includes $0.4 million and $1.2 million for the three and nine months ended September 30, 2012, respectively, and $0.2 million and $1.0 million for the three and nine months ended September 30, 2011, respectively, of interest income related to a capital lease (see *Note 2 Acquisitions* included in *the Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q).

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In addition, other income (expense), net for the nine months ended September 30, 2012, includes a realized loss of $1.7 million resulting from U.S. Treasury Rate lock agreements settled simultaneously with our June 2012 issuance of the 2022 Notes. Other income (expense), net for the nine months ended September 30, 2011, includes the reversal of an unrealized gain of $1.7 million, previously recorded in March 2011, and a realized loss of $1.9 million, upon termination of the interest-rate swap agreement in May 2011 concurrent with the issuance of the 2021 Notes (see *Note 7 Debt and Interest Expense* included in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q).

Income Tax Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2012**	**2011**	D	**2012**	**2011**	D
Income before income taxes	**$ 43,012**	$ 53,847	(20)%	**$ 136,612**	$ 159,458	(14)%
Income tax expense	**72**	4,668	(98)%	**699**	15,564	(96)%
Effective tax rate	**%**	9%		**1%**	10%	

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 MGR assets prior to and including January 2012 and (b) the Bison assets prior to and including June 2011 were subject to federal and state income tax, resulting in the lower income tax expense for the three and nine months ended September 30, 2012. Income earned by the Bison and MGR assets for periods subsequent to June 2011 and January 2012, respectively, was subject only to Texas margin tax on the portion of their incomes apportionable to Texas.

For 2012 and 2011, our variance from the federal statutory rate, which is zero percent as a non-taxable entity, is primarily attributable to federal and state taxes on pre-acquisition income attributable to Partnership assets and our share of Texas margin tax.

Noncontrolling Interests

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	**2012**	**2011**	D	**2012**	**2011**	D
Net income attributable to noncontrolling interests	**$ 3,423**	$ 3,873	(12)%	**$ 11,956**	$ 9,665	24%

For the three months ended September 30, 2012, net income attributable to noncontrolling interests decreased by $0.5 million, primarily due to the acquisition of Anadarko s remaining 24% membership interest in Chipeta in August 2012. See *Note 2 Acquisitions* included in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

For the nine months ended September 30, 2012, net income attributable to noncontrolling interests increased by $2.3 million, primarily due to higher volumes at the Chipeta system, partially offset by the acquisition of Anadarko s remaining 24% membership interest in Chipeta in August 2012.

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KEY PERFORMANCE METRICS

thousands except percentages and gross margin per Mcf	Three Months Ended September 30, 2012	2011	D	Nine Months Ended September 30, 2012	2011	D
Gross margin	**$ 129,913**	$ 127,880	2%	**$ 381,884**	$ 367,303	4%
Gross margin per Mcf (1)	**0.53**	0.56	(5)%	**0.52**	0.55	(5)%
Gross margin per Mcf attributable to Western Gas Partners, LP (2)	**0.55**	0.59	(7)%	**0.55**	0.58	(5)%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	**84,497**	82,256	3%	**244,349**	241,284	1%
Distributable cash flow (3)	**$ 64,360**	$ 66,934	(4)%	**$ 197,285**	$ 211,313	(7)%

(1) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total natural gas throughput, including 100% of gross margin and volumes attributable to Chipeta, our 14.81% interest in income and volumes attributable to Fort Union and our 22% interest in income and volumes attributable to Rendezvous.

(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 the Partnership. Calculation includes income attributable to our investments in Fort Union, White Cliffs and Rendezvous and volumes attributable to our investments in Fort Union and Rendezvous.

(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 $2.0 million for the three months ended September 30, 2012, primarily due to increased margins at the Wattenberg system due to an increase in volumes and increased margins driven by volumes processed at a plant included in the MGR acquisition under a new contract effective January 2012, with no volumes in the comparable period. These increases were partially offset by lower margins at the Platte Valley system attributable to declines in price and lower margins at the Red Desert complex as a result of price declines and commodity price swap agreements associated with the MGR acquisition, which became effective in January 2012.

Gross margin increased by $14.6 million for the nine months ended September 30, 2012, primarily due to: higher margins at the Wattenberg and Chipeta systems due to increases in volumes sold (including the impact of commodity price swap agreements at the Wattenberg system); higher margins driven by volumes processed at a plant included in the MGR acquisition under a new contract effective January 2012, with no volumes in the comparable period; and an increase in volumes at White Cliffs. These increases were partially offset by lower gross margins at the Red Desert complex due to price declines, as well as commodity price swap agreements associated with the MGR acquisition, which became effective in January 2012. Gross margin increases were also partially offset by lower gross margins at the Hugoton system due to decreased drip condensate volumes sold.

For the three months ended September 30, 2012, gross margin per Mcf decreased $0.03, primarily due to declines in price, an increase in cost of product as a result of commodity price swap agreements associated with the MGR acquisition that became effective in January 2012, and to a lesser extent, lower volumes at the Platte Valley system and the Red Desert complex. These declines were partially offset by an increase in gross margin per Mcf at the Hilight and Hugoton systems as a result of disproportionate decreases in volume and price decreases.

For the nine months ended September 30, 2012, gross margin per Mcf decreased by $0.03, primarily due to a decrease in volumes sold at the Red Desert complex, coupled with an increase in cost of product as a result of commodity price swap agreements associated with the MGR acquisition which became effective in January 2012. These declines were partially offset by increases at the Wattenberg and Chipeta systems due to increases in volumes sold (including the impact of commodity price swap agreements at the Wattenberg system) and an increase in gross margin per Mcf at the Hilight system as a result of a disproportionate decrease in volume and price.

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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, expense in excess of the expense reimbursement cap provided in our omnibus agreement (which cap is no longer effective), interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, and other income. 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 that 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 $2.2 million for the three months ended September 30, 2012, primarily due to a $1.6 million increase in distributions from equity investees, a $1.1 million decrease in general and administrative expenses excluding non-cash equity-based compensation, a $0.6 million decrease in cost of product, a $0.5 million decrease in net income attributable to noncontrolling interests, a $0.3 million increase in total revenues excluding equity income and a $0.3 million decrease in depreciation expense, partially offset by a $1.5 million increase in operation and maintenance expenses and a $0.7 million increase in property and other taxes expense.

Adjusted EBITDA increased by $3.1 million for the nine months ended September 30, 2012, primarily due to a $25.5 million increase in total revenues excluding equity income, a $3.6 million increase in distributions from equity investees, a $0.6 million decrease in general and administrative expenses excluding non-cash equity-based compensation and a $0.4 million decrease in depreciation expense, partially offset by a $14.0 million increase in cost of product, a $9.2 million increase in operation and maintenance expenses, a $2.3 million increase in net income attributable to noncontrolling interests, a $1.6 million increase in property and other taxes expense.

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 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. 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.

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Distributable cash flow should not be considered an alternative to net income, earnings per unit, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Furthermore, while Distributable cash flow is a measure we use to assess 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.

Distributable cash flow decreased by $2.6 million for the three months ended September 30, 2012, primarily due to a $4.1 million increase in net cash paid for interest expense, a $0.5 million increase in cash paid for maintenance capital expenditures and a $0.2 million increase in cash paid for income taxes, partially offset by the $2.2 million increase in Adjusted EBITDA.

Distributable cash flow decreased by $14.0 million for the nine months ended September 30, 2012, primarily due to a $11.8 million increase in net cash paid for interest expense, a $5.0 million increase in cash paid for maintenance capital expenditures and a $0.3 million increase in cash paid for income taxes, partially offset by the $3.1 million increase in Adjusted EBITDA.

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, and 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 and Distributable cash flow have important limitations as analytical tools because they exclude 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.

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.

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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:

thousands	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Reconciliation of Adjusted EBITDA to Net income attributable to Western Gas Partners, LP				
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 84,497**	$ 82,256	**$ 244,349**	$ 241,284
Less:				
Distributions from equity investees	**5,584**	3,988	**15,603**	11,988
Non-cash equity-based compensation expense	**9,417**	2,389	**16,407**	6,235
Interest expense	**10,977**	8,930	**30,118**	21,738
Income tax expense	**72**	4,668	**699**	15,564
Depreciation, amortization and impairments (1)	**27,084**	28,215	**79,514**	76,282
Other expense (1)			**1,665**	3,683
Add:				
Equity income, net	**3,804**	2,660	**10,752**	7,682
Interest income, net affiliates	**4,225**	8,573	**12,675**	18,992
Other income (1) (2)	**125**	7	**187**	1,761
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229
Reconciliation of Adjusted EBITDA to Net cash provided by operating activities				
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 84,497**	$ 82,256	**$ 244,349**	$ 241,284
Adjusted EBITDA attributable to noncontrolling interests	**3,866**	4,593	**13,709**	11,793
Interest income (expense), net	**(6,752)**	(357)	**(17,443)**	(2,746)
Non-cash equity-based compensation expense	**(9,417)**	(2,389)	**(16,407)**	(6,235)
Current income tax expense	**(60)**	(5,477)	**(185)**	(10,882)
Other income (expense), net (2)	**126**	7	**(1,475)**	(1,919)
Distributions from equity investees less than (in excess of) equity income, net	**(1,780)**	(1,328)	**(4,851)**	(4,306)
Changes in operating working capital:				
Accounts receivable and natural gas imbalance receivable	**(604)**	1,891	**5,062**	(18,925)
Accounts payable, accrued liabilities and natural gas imbalance payable	**62,600**	16,301	**71,420**	30,359
Other	**(3,766)**	(334)	**621**	4,978
Net cash provided by operating activities	**$ 128,710**	$ 95,163	**$ 294,800**	$ 243,401
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			**$ 294,800**	$ 243,401
Net cash used in investing activities			**$ (899,943)**	$ (405,241)
Net cash provided by financing activities			**$ 426,078**	$ 386,223

(1) Includes our 51% share prior to August 1, 2012, and our 75% share after August 1, 2012, of depreciation, amortization and impairments; other expense; and other income attributable to Chipeta.

(2) Excludes income of $0.4 million and $1.2 million for the three and nine months ended September 30, 2012, respectively, and $0.2 million and $1.0 million for the three and nine months ended September 30, 2011, respectively, related to a component of a gas processing

agreement accounted for as a capital lease. See *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

thousands except Coverage ratio	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP and calculation of the Coverage ratio				
Distributable cash flow	**$ 64,360**	$ 66,934	**$ 197,285**	$ 211,313
Less:				
Distributions from equity investees	**5,584**	3,988	**15,603**	11,988
Non-cash equity-based compensation expense	**9,417**	2,389	**16,407**	6,235
Interest expense, net (non-cash settled)	**81**		**244**	
Income tax expense	**72**	4,668	**699**	15,564
Depreciation, amortization and impairments [(1)]	**27,084**	28,215	**79,514**	76,282
Other expense [(1)]			**1,665**	3,683
Add:				
Equity income, net	**3,804**	2,660	**10,752**	7,682
Cash paid for maintenance capital expenditures [(1) (2)]	**10,819**	10,306	**25,543**	20,584
Capitalized interest	**2,224**	121	**3,827**	134
Cash paid for income taxes	**423**	190	**495**	190
Other income [(1) (3)]	**125**	7	**187**	1,761
Interest income, net (non-cash settled)		4,348		6,317
Net income attributable to Western Gas Partners, LP	**$ 39,517**	$ 45,306	**$ 123,957**	$ 134,229
Distributions declared [(4)]				
Limited partners	**$ 47,968**		**$ 135,699**	
General partner	**8,378**		**19,125**	
Total	**$ 56,346**		**$ 154,824**	
Coverage ratio	**1.14 x**		**1.27 x**	

(1) Includes our 51% share prior to August 1, 2012, and our 75% share after August 1, 2012, of depreciation, amortization and impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to Chipeta.

(2) Net of a prior period adjustment reclassifying approximately $0.7 million from capital expenditures to operating expenses for the nine months ended September 30, 2012.

(3) Excludes income of $0.4 million and $1.2 million for the three and nine months ended September 30, 2012, respectively, and $0.2 million and $1.0 million for the three and nine months ended September 30, 2011, respectively, related to a component of a gas processing agreement accounted for as a capital lease. See *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

(4) Reflects distributions of $0.50 and $1.44 per unit declared for the three and nine months ended September 30, 2012, respectively.

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, 2012, included cash and cash equivalents, cash flows generated from operations, including interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional equity or debt securities. As of September 30, 2012, we had issued letters of credit totaling $0.3 million, which reduces our available borrowing capacity under the RCF by such amount. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, 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 equity and debt 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 RCF 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 each quarter since our initial public offering and have increased our quarterly distribution each quarter since the second quarter of 2009. On October 11, 2012, the board of directors of our general partner declared a cash distribution to our unitholders of $0.50 per unit, or $56.3 million in aggregate, including incentive distributions. The cash distribution is payable on November 13, 2012, to unitholders of record at the close of business on October 31, 2012.

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 statements. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read Part II, Item 1A *Risk Factors* of this Form 10-Q.

Working capital. As of September 30, 2012, we had a $131.8 million working capital deficit, which we define as the amount by which current liabilities exceed current assets. 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. Our working capital deficit as of September 30, 2012, is primarily due to the costs incurred for the continued construction of the Brasada and Lancaster plants, as well as the $18.9 million cost reimbursement payable related to the construction of the Brasada and Lancaster plants described in *Note 5 Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q

Capital expenditures. Our business is capital intensive, requiring significant investment to maintain and improve existing facilities or develop new midstream infrastructure. 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 expenditures to construct new midstream infrastructure and 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.

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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 as presented in the consolidated statements of cash flows and capital incurred were as follows:

	Nine Months Ended September 30,	
thousands	**2012**	**2011**
Acquisitions	**$ 605,960**	$ 326,957
Expansion capital expenditures	**$ 268,305**	$ 57,893
Maintenance capital expenditures	**26,291**	20,680
Total capital expenditures [(1)]	**$ 294,596**	$ 78,573
Capital incurred [(2)]	**$ 356,090**	$ 88,223

(1) Capital expenditures for the nine months ended September 30, 2011, included $9.5 million of pre-acquisition capital expenditures for the MGR and Bison assets and included the noncontrolling interest owners share of Chipeta s capital expenditures, funded by contributions from the noncontrolling interest owners. Capital expenditures for the nine months ended September 30, 2012, excluded $3.8 million of capitalized interest.

(2) Capital incurred for the nine months ended September 30, 2011, included $7.9 million of pre-acquisition capital incurred for the MGR and Bison assets and included the noncontrolling interest owners share of Chipeta s capital incurred, funded by contributions from the noncontrolling interest owners.

Acquisitions included Anadarko s remaining 24% membership interest in Chipeta, and the MGR, Bison, Platte Valley acquisitions as outlined in *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

Capital expenditures, excluding acquisitions, increased by $216.0 million for the nine months ended September 30, 2012. Expansion capital expenditures increased by $210.4 million for the nine months ended September 30, 2012, primarily due to an increase of $112.0 million in expenditures at our Wattenberg, Chipeta, and Platte Valley systems and at the Red Desert complex, and $106.2 million related to the construction of the Brasada and Lancaster gas processing facilities. These increases were partially offset by a $6.3 million decrease related to the Bison assets, due to the continued startup costs incurred in early 2011, and a $1.2 million decrease at the Hilight system. Maintenance capital expenditures increased by $5.6 million, primarily as a result of increased expenditures of $6.5 million due to higher well connects at the Platte Valley, Wattenberg, Haley and Hilight systems and the Red Desert complex and a prior period adjustment of $0.7 million recorded during the nine months ended September 30, 2012, partially offset by $1.6 million in improvements at the Hugoton system, completed during 2011.

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

	Nine Months Ended September 30,	
thousands	**2012**	**2011**
Net cash provided by (used in):		
Operating activities	**$ 294,800**	$ 243,401
Investing activities	**(899,943)**	(405,241)
Financing activities	**426,078**	386,223

Net increase (decrease) in cash and cash equivalents	**$ (179,065)**	$ 224,383

Operating Activities. For expanded discussion, refer to *Operating Results* within this Item 2 of this Form 10-Q. Net cash provided by operating activities increased by $51.4 million for the nine months ended September 30, 2012, primarily due to the following items:

a $41.1 million increase due to changes in accounts and natural gas imbalance payable and accrued liabilities, net, primarily as a result of accrued liabilities for the continued construction of the Brasada and Lancaster plants;

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- a $25.5 million increase in revenues, excluding equity income, due to increased processing throughput as a result of increased drilling activity in certain of WES s operating areas, WES s realization of higher average commodity prices under its fixed-price swap agreements and the addition of the Platte Valley assets in March 2011;
- a $22.1 million increase due to changes in accounts receivable balances;
- a $10.7 million decrease in current income tax expense;
- a $3.0 million increase in equity income; and
- a $0.6 million decrease in other expense.

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

- a $14.0 million increase in cost of product expense, due to increased processing throughput as a result of increased drilling activity in certain of WES s operating areas and the addition of the Platte Valley assets in March 2011;
- a $9.6 million increase in general and administrative expenses, primarily due to increased compensation expense;
- a $9.2 million increase in operation and maintenance expense;
- an $8.4 million increase in interest expense, primarily due to the 2022 Notes offering in June 2012;
- a $6.3 million decrease in interest income;
- a $2.5 million decrease due to changes in other items, net, primarily due to increases related to the Western Gas Partners, LP 2008 Long-Term Incentive Plan and the accretion of asset retirement obligations; and
- a $1.7 million increase in property and other taxes expense.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2012, included the following:

- $458.6 million of cash paid for the MGR acquisition;
- $294.6 million of capital expenditures;
- $128.3 million of cash paid for the additional 24% membership interest in Chipeta; and

- $18.9 million of cash paid for equipment purchases from Anadarko;

Net cash used in investing activities for the nine months ended September 30, 2011, included the following:

- $302.0 million of cash paid for the Platte Valley acquisition;
- $25.0 million of cash paid for the Bison acquisition; and
- $78.6 million of capital expenditures.

Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2012, included the following:

- $511.3 million of net proceeds from our 2022 Notes offering in June 2012, after underwriting and original issue discounts and offering costs;
- $299.0 million of borrowings to fund the MGR acquisition; and
- $216.4 million of net proceeds from our June 2012 equity offering.

Proceeds from our 2022 Notes offering were used to repay amounts outstanding under our RCF and our note payable to Anadarko.

Net contributions from Anadarko attributable to intercompany balances were $2.2 million during 2012, representing the settlement of intercompany transactions attributable to the Bison assets.

Net cash provided by financing activities for the nine months ended September 30, 2011, included the following:

- $489.7 million of net proceeds from our 2021 Notes offering in May 2011, after underwriting and original issue discounts and offering costs;
- $303.0 million of borrowings to fund the Platte Valley acquisition;
- $250.0 million repayment of the Wattenberg term loan (described below) using borrowings from our RCF;
- $202.8 million of net proceeds from our September 2011 equity offering; and
- $132.6 million of net proceeds from our March 2011 equity offering.

Proceeds from our 2021 Notes offering and our March 2011 equity offering were used to repay amounts outstanding under our RCF.

Net distributions to Anadarko attributable to pre-acquisition intercompany balances were $42.9 million during 2011, representing the net non-cash settlement of intercompany transactions attributable to the MGR and Bison assets.

For the nine months ended September 30, 2012 and 2011, we paid $141.5 million and $99.8 million, respectively, of cash distributions to our unitholders. Contributions from noncontrolling interest owners to Chipeta totaled $26.9 million and $16.9 million during the nine months ended September 30, 2012 and 2011, respectively, primarily for expansion of the cryogenic units and plant construction. Distributions from Chipeta to noncontrolling interest owners totaled $14.3 million and $10.2 million for the nine months ended September 30, 2012 and 2011, 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, 2012, our outstanding debt consisted of $515.9 million of the 2022 Notes and $494.5 million of the 2021 Notes. See *Note 7 Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

4.000% Senior Notes due 2022. In June 2012, we completed the offering of the 2022 Notes at a price to the public of 99.194% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate is 4.207%. Interest will be paid semi-annually on January 1 and July 1 of each year, commencing on January 1, 2013. The 2022 Notes will mature on July 1, 2022, unless redeemed, in whole or in part, at any time prior to maturity, at a redemption price that includes a make-whole premium. Proceeds (net of underwriting discount of

$3.4 million and debt issuance costs) were used to repay all amounts then outstanding under our RCF and the $175.0 million note payable to Anadarko (see below).

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The 2022 Notes indenture contains customary events of default including, among others, (i) default for 30 days in the payment of interest when due on the 2022 Notes; (ii) default in payment, when due, of principal of or premium, if any, on the 2022 Notes at maturity, upon redemption or otherwise; and (iii) certain events of bankruptcy or insolvency. The 2022 Notes indenture also contains covenants that limit, among other things, our ability, as well as that of certain of our subsidiaries, 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, 2012, we were in compliance with all covenants under the 2022 Notes.

Refer to *Note 9 Subsequent Event* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q, for a discussion of the additional offering of the 2022 Notes in October 2012.

5.375% Senior Notes due 2021. In May 2011, we completed the offering of the 2021 Notes at a price to the public of 98.778% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate is 5.648%.

Upon issuance, the 2021 Notes were fully and unconditionally guaranteed on a senior unsecured basis by each of our wholly owned subsidiaries (the Subsidiary Guarantors). The Subsidiary Guarantors guarantees were immediately released on June 13, 2012, upon the Subsidiary Guarantors becoming released from their obligations under our RCF, as discussed below. At September 30, 2012, we were in compliance with all covenants under the 2021 Notes.

Note payable to Anadarko. In December 2008, we entered into a five-year $175.0 million term loan agreement with Anadarko. The term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity in 2013. In June 2012, the note payable to Anadarko was repaid in full with proceeds from issuance of the 2022 Notes.

Revolving credit facility. In March 2011, we entered into an amended and restated $800.0 million senior unsecured RCF 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 (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%, or (c) LIBOR plus 1%, in each case 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.

On June 13, 2012, following the receipt of a second investment grade rating, as defined in our RCF, the guarantees provided by our wholly owned subsidiaries were released, and we are no longer subject to certain of the restrictive covenants associated with the RCF, including the maintenance of an interest coverage ratio and adherence to covenants that limit, among other things, our ability, and that of certain of our subsidiaries, to dispose of assets and make certain investments or payments. We did not have outstanding borrowings under our $800.0 million RCF as of September 30, 2012, and had $0.3 million in outstanding letters of credit issued under the facility. At September 30, 2012, we were in compliance with all remaining covenants under the RCF.

The 2022 Notes, the 2021 Notes and obligations under the RCF are recourse to our general partner. In turn, our general partner has been indemnified by a wholly owned subsidiary of Anadarko against any claims made against the general partner under the 2022 Notes, the 2021 Notes and/or the RCF.

Wattenberg term loan. We repaid the $250.0 million Wattenberg term loan in full 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 U.S. Securities and Exchange Commission.

In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to $125.0 million of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of September 30, 2012, we had not issued any common units under this registration statement.

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. A substantial portion of our throughput, however, comes from producers that have investment-grade ratings.

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, 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, Anadarko s note payable to us, our omnibus agreement, the services and secondment agreement, contribution agreements or the commodity price swap agreements.

CONTRACTUAL OBLIGATIONS

Our contractual obligations include, among other things, a revolving credit facility, other third-party long-term debt, capital obligations related to our expansion projects and various operating leases. Refer to *Note 7 Debt and Interest Expense* and *Note 8 Commitments and Contingencies* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q for an update to our contractual obligations as of September 30, 2012, including, but not limited to, the issuance of the 2022 Notes, the repayment of our note payable to Anadarko and increases in committed capital.

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 Item 1 of this Form 10-Q.

RECENT ACCOUNTING DEVELOPMENTS

Recently adopted accounting standard. In May 2011, the Financial Accounting Standards Board (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 and disclosure requirements, changes the fair value measurement requirements for certain financial instruments, and sets forth additional disclosure requirements for other fair value measurements. The ASU is to be applied prospectively and is effective for periods beginning after December 15, 2011. We adopted the ASU effective January 1, 2012. The adoption of the requirements of the ASU, which expanded disclosures, had no effect on our results of operations or financial position.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk. 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 commodity price swap agreements with Anadarko expiring at various times through December 2016. For additional information on the commodity price swap agreements, see *Note 5 Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

In addition, 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.

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, as well as instances where our actual liquids recovery or fuel usage varies from the contractually stipulated amounts. 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 2011 and the nine months ended September 30, 2012 were low compared to historic rates. As of September 30, 2012, we had no borrowings outstanding under our RCF, which bears interest at a variable rate based on LIBOR. If interest rates rise, our future financing costs could increase if we incur borrowings under our RCF. For the three months ended September 30, 2012, a 10% change in LIBOR would have resulted in a nominal change in net income.

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

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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 (Exchange Act). 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, 2012.

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, 2012, 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 results of operations, cash flows or financial condition, or for which disclosure is otherwise required by Item 103 of Regulation S-K.

Item 1A. Risk Factors

Security holders and potential investors in our securities should carefully consider the risk factors under Part I, Item 1A set forth in our Form 10-K for the year ended December 31, 2011, together with all of the other information included in this document; the Partnership s Form 10-K, certain sections of which were recast to reflect the results of the MGR assets (as defined in *Note 2 Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q) in our Current Report on Form 8-K, as filed with the SEC on May 22, 2012; and in our other public filings, press releases, and public 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 Form 10-K for the year ended December 31, 2011, Anadarko s quarterly reports on Form 10-Q and Anadarko s other public filings, press releases, and public 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.

Recently approved final rules regulating air emissions from natural gas processing operations could cause us to incur increased capital expenditures and operating costs, which may be significant.

On August 16, 2012, the EPA published final rules that establish new air emission controls for natural gas and natural gas liquids production, processing and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with production and processing activities. Among other things, the rules establish specific requirements regarding emissions from compressors and controllers at natural gas gathering and boosting stations and processing plants together with dehydrators and storage tanks at natural gas processing plants, compressor stations and gathering and boosting stations. In addition, the rules establish new requirements for leak detection and repair of leaks at natural gas processing plants that exceed 500 parts per million in concentration. We are currently reviewing this new rule and assessing its potential impacts. Compliance with these requirements may require modifications to certain of our operations, including the installation of new equipment to control emissions from our compressors that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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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).
2.7	Contribution Agreement, dated as of December 15, 2011, 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 December 15, 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).

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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	Amendment No. 7 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated January 13, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on January 17, 2012, File No. 001-34046).
3.10	Amendment No. 8 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 1, 2012 (incorporated by reference to Exhibit 3.10 to Western Gas Partners, LP s Quarterly Report on Form 10-Q filed on August 2, 2012, File No. 001-34046)
3.11	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).
3.12	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).
4.5	Fourth Supplemental Indenture, dated as of June 28, 2012, among Western Gas Partners, LP, as Issuer, 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 June 28, 2012, File No. 001-34046).
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP s Current Report on Form 8-K filed on June 28, 2012, 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.DEF**	XBRL Definition Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation 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 1, 2012

/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 1, 2012

/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)