Western Gas Partners LP
Form 10-Q
July 27, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2016

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 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 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	Accelerated filer	Non-accelerated filer	Smaller reporting company
	(Do not check if a 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

There were 130,671,970 common units outstanding as of July 25, 2016.

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, references to "we," "us," "our," the "Partnership" or "Western Gas Partners, LP" refer to Western Gas Partners, LP and its subsidiaries. As used in this Form 10-Q, the terms below have the following meanings:
Affiliates: Subsidiaries of Anadarko, excluding us, but including equity interests in Fort Union, White Cliffs, Rendezvous, the Mont Belvieu JV, TEP, TEG, and FRP.
Anadarko: Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner.
Anadarko-Operated Marcellus Interest: Our 33.75% interest in the Larry's Creek, Seely and Warrensville gas gathering systems and related facilities located in northern Pennsylvania.
April 2016 Series A units: The 7,892,220 Series A Preferred units issued pursuant to the full exercise of the option granted in connection with the issuance of the March 2016 Series A units.
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.
Chipeta: Chipeta Processing, LLC.
Condensate: A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
COP: Continuous offering programs.
Cryogenic: The process in which liquefied gases are used to bring natural gas 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.
DBJV: Delaware Basin JV Gathering LLC.
DBJV system: A gathering system and related facilities located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties, Texas.
DBM: Delaware Basin Midstream, LLC.
DBM complex: The cryogenic processing plants, gas gathering system, and related facilities and equipment that serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.
DJ Basin complex: The Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.
EBITDA: Earnings before interest, taxes, depreciation, and amortization. For a definition of "Adjusted EBITDA," see the caption Key Performance Metrics under Part I, Item 2 of this Form 10-Q.
Equity investment throughput: Our 14.81% share of average Fort Union throughput, 22% share of average Rendezvous throughput, 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput.
Exchange Act: The Securities Exchange Act of 1934, as amended.
Fort Union: Fort Union Gas Gathering, LLC.
FRP: Front Range Pipeline LLC.
GAAP: Generally accepted accounting principles in the United States.

General partner: Western Gas Holdings, LLC.
Imbalance: Imbalances result from (i) differences between gas and NGL volumes nominated by customers and gas and NGL volumes received from those customers and (ii) differences between gas and NGL volumes received from customers and gas and NGL volumes delivered to those customers.
IPO: Initial public offering.
LIBOR: London Interbank Offered Rate.
March 2016 Series A units: The 14,030,611 Series A Preferred units issued in March 2016 in connection with the acquisition of Springfield.
MBbls/d: One thousand barrels per day.
MGR assets: The Red Desert complex, the Granger straddle plant and the 22% interest in Rendezvous.
MICG: MIGC, LLC.
MLP: Master limited partnership.
MMBtu: One million British thermal units.
MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
Mont Belvieu JV: Enterprise EF78 LLC.
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.
Non-Operated Marcellus Interest: Our 33.75% interest in the Liberty and Rome gas gathering systems and related facilities located in northern Pennsylvania.
PIK Class C units: Additional Class C units issued as quarterly distributions to the holder of our Class C units.
RCF: Our senior unsecured revolving credit facility.
Red Desert complex: The Patrick Draw processing plant, the Red Desert processing plant, associated gathering lines, and related facilities.
Rendezvous: Rendezvous Gas Services, LLC.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
SEC: U.S. Securities and Exchange Commission.
Springfield: Springfield Pipeline LLC.
Springfield interest: Springfield’s 50.1% interest in the Springfield system.
Springfield gas gathering system: A gas gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield oil gathering system: An oil gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield system: Consists of the Springfield gas gathering system and Springfield oil gathering system.
TEFR Interests: The interests in TEP, TEG and FRP.

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TEG: Texas Express Gathering LLC.
TEP: Texas Express Pipeline LLC.
WGP: Western Gas Equity Partners, LP.
White Cliffs: White Cliffs Pipeline, LLC.
2018 Notes: Our 2.600% Senior Notes due 2018.
2021 Notes: Our 5.375% Senior Notes due 2021.
2022 Notes: Our 4.000% Senior Notes due 2022.
2025 Notes: Our 3.950% Senior Notes due 2025.
2044 Notes: Our 5.450% Senior Notes due 2044.
2026 Notes: Our 4.650% Senior Notes due 2026.
$500.0 million COP: The COP contemplated by the registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of our common units.

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PART I. FINANCIAL INFORMATION (UNAUDITED)
Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands except per-unit amounts	2016	2015 [1]	2016	2015 [1]
Revenues and other – affiliates				
Gathering, processing and transportation	$186,733	$199,666	$374,451	$387,684
Natural gas and natural gas liquids sales	115,672	121,613	200,538	240,353
Other	—	132	—	302
Total revenues and other – affiliates	302,405	321,411	574,989	628,339
Revenues and other – third parties				
Gathering, processing and transportation	114,403	91,234	220,689	173,484
Natural gas and natural gas liquids sales	11,321	52,589	15,011	99,521
Other	535	759	1,116	1,655
Total revenues and other – third parties	126,259	144,582	236,816	274,660
Total revenues and other	428,664	465,993	811,805	902,999
Equity income, net – affiliates	19,693	18,941	36,507	37,161
Operating expenses				
Cost of product [2]	104,849	147,216	181,316	286,624
Operation and maintenance [2]	75,173	77,837	151,386	154,022
General and administrative [2]	10,883	9,408	22,160	20,489
Property and other taxes	12,078	9,586	22,428	18,866
Depreciation and amortization	67,305	68,554	132,400	137,529
Impairments	2,403	1,620	8,921	274,244
Total operating expenses	272,691	314,221	518,611	891,774
Gain (loss) on divestiture and other, net	(1,907)	—	(2,539)	(6)
Proceeds from business interruption insurance claims	2,603	—	2,603	—
Operating income (loss)	176,362	170,713	329,765	48,380
Interest income – affiliates	4,225	4,225	8,450	8,450
Interest expense [3]	(12,883)	(27,604)	(44,919)	(50,564)
Other income (expense), net	(53)	71	71	142
Income (loss) before income taxes	167,651	147,405	293,367	6,408
Income tax (benefit) expense	326	12,246	6,959	24,516
Net income (loss)	167,325	135,159	286,408	(18,108)
Net income attributable to noncontrolling interest	2,804	2,816	5,827	6,042
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Limited partners' interest in net income (loss):				
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Pre-acquisition net (income) loss allocated to Anadarko	—	(18,719)	(11,326)	(43,758)
Series A Preferred units interest in net (income) loss [4]	(23,121)	—	(25,450)	—
General partner interest in net (income) loss [4]	(58,381)	(45,971)	(113,781)	(83,148)
Common and Class C limited partners' interest in net income (loss) [4]	83,019	67,653	130,024	(151,056)
Net income (loss) per common unit – basic and diluted [5]	$0.55	$0.46	$0.86	$(1.14)

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

(2) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $22.1 million and $46.7 million for the three and six months ended June 30, 2016, respectively, and $53.1 million and $97.0 million for the three and six months ended June 30, 2015, respectively. Operation and maintenance includes charges from Anadarko of $17.7 million and $35.6 million for the three and six months ended June 30, 2016, respectively, and $19.9 million and $36.7 million for the three and six months ended June 30, 2015, respectively. General and administrative includes charges from Anadarko of $9.2 million and $18.1 million for the three and six months ended June 30, 2016, respectively, and $8.1 million and $16.2 million for the three and six months ended June 30, 2015, respectively. See Note 5.

(3) Includes affiliate (as defined in Note 1) amounts of $(15.5) million and $(10.9) million for the three and six months ended June 30, 2016, respectively, and $4.2 million and $5.6 million for the three and six months ended June 30, 2015, respectively. See Note 2 and Note 9.

(4) Represents net income (loss) earned on and subsequent to the date of acquisition of the Partnership assets (as defined in Note 1). See Note 4.

(5) See Note 4 for the calculation of net income (loss) per common unit.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	June 30, 2016	December 31, 2015 [1]
ASSETS		
Current assets		
Cash and cash equivalents	$157,767	$98,033
Accounts receivable, net [2]	221,795	193,329
Other current assets	5,691	7,855
Total current assets	385,253	299,217
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	6,818,174	6,556,778
Less accumulated depreciation	1,816,030	1,697,999
Net property, plant and equipment	5,002,144	4,858,779
Goodwill	419,186	419,186
Other intangible assets	817,913	832,127
Equity investments	606,125	618,887
Other assets	13,481	13,001
Total assets	$7,504,102	$7,301,197
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables	$90,914	$98,661
Accrued ad valorem taxes	20,633	17,808
Accrued liabilities	130,018	119,019
Total current liabilities	241,565	235,488
Long-term debt	2,932,004	2,690,651
Deferred income taxes	6,020	139,704
Asset retirement obligations and other	137,139	128,652
Deferred purchase price obligation – Anadarko [3]	29,150	188,674
Total long-term liabilities	3,104,313	3,147,681
Total liabilities	3,345,878	3,383,169
Equity and partners' capital		
Series A Preferred units (21,922,831 and zero units issued and outstanding at June 30, 2016, and December 31, 2015, respectively) [4]	617,094	—
Common units (130,671,970 and 128,576,965 units issued and outstanding at June 30, 2016, and December 31, 2015, respectively)	2,613,806	2,588,991
Class C units (11,946,008 and 11,411,862 units issued and outstanding at June 30, 2016, and December 31, 2015, respectively) [5]	729,731	710,891
General partner units (2,583,068 units issued and outstanding at June 30, 2016, and December 31, 2015)	131,842	120,164
Net investment by Anadarko	—	430,598
Total partners' capital	4,092,473	3,850,644
Noncontrolling interest	65,751	67,384
Total equity and partners' capital	4,158,224	3,918,028
Total liabilities, equity and partners' capital	$7,504,102	$7,301,197

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

(2) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $81.3 million and $42.7 million as of June 30, 2016, and December 31, 2015, respectively. Accounts receivable, net as of June 30, 2016, and December 31, 2015, also includes an insurance claim receivable related to an incident at the DBM complex. See Note 1.

(3) See Note 2.

(4) The Series A Preferred units are convertible into common units at the holder's election on a one-for-one basis at any time after the second anniversary of the issuance date. See Note 4.

(5) The Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. See Note 4.

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	Class C Units	Series A Preferred Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2015 [(1)]	$430,598	$2,588,991	$710,891	$—	$120,164	$ 67,384	$3,918,028
Net income (loss)	11,326	126,292	13,213	15,969	113,781	5,827	286,408
Above-market component of swap extensions with Anadarko [(2)]	—	16,365	—	—	—	—	16,365
Issuance of common units, net of offering expenses	—	25,000	—	—	—	—	25,000
Issuance of Series A Preferred units, net of offering expenses	—	—	—	686,940	—	—	686,940
Beneficial conversion feature of Series A Preferred units	—	93,409	—	(93,409)	—	—	—
Amortization of beneficial conversion feature of Class C units and Series A Preferred units	—	(15,108)	5,627	9,481	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(7,460)	(7,460)
Distributions to unitholders	—	(209,355)	—	(1,887)	(102,138)	—	(313,380)
Acquisitions from affiliates	(549,865)	(162,635)	—	—	—	—	(712,500)
Revision to Deferred purchase price obligation – Anadarko [(3)]	—	148,600	—	—	—	—	148,600
Contributions of equity-based compensation from Anadarko	—	2,012	—	—	41	—	2,053
Net pre-acquisition contributions from (distributions to) Anadarko	(27,459)	—	—	—	—	—	(27,459)
Net distributions to Anadarko of other assets	—	(348)	—	—	(6)	—	(354)
Elimination of net deferred tax liabilities	135,400	—	—	—	—	—	135,400
Other	—	583	—	—	—	—	583
Balance at June 30, 2016	$—	$2,613,806	$729,731	$617,094	$131,842	$ 65,751	$4,158,224

(1) Financial information has been recast to include the financial position and results attributable to the Springfield interest. See Note 1 and Note 2.
(2) See Note 5.
(3) See Note 2.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ended June 30,	
thousands	2016	2015 [1]
Cash flows from operating activities		
Net income (loss)	$286,408	$(18,108)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	132,400	137,529
Impairments	8,921	274,244
Non-cash equity-based compensation expense	2,391	2,130
Deferred income taxes	1,980	6,382
Accretion and amortization of long-term obligations, net	(9,055)	7,070
Equity income, net – affiliates	(36,507)	(37,161)
Distributions from equity investment earnings – affiliates	38,519	39,034
(Gain) loss on divestiture and other, net	2,539	6
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	(33,242)	(41,358)
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	(2,227)	4,407
Change in other items, net	1,739	(1,854)
Net cash provided by operating activities	393,866	372,321
Cash flows from investing activities		
Capital expenditures	(255,923)	(361,798)
Contributions in aid of construction costs from affiliates	3,854	—
Acquisitions from affiliates	(715,199)	(9,056)
Acquisitions from third parties	—	(3,514)
Investments in equity affiliates	139	(6,770)
Distributions from equity investments in excess of cumulative earnings – affiliates	10,611	8,538
Proceeds from the sale of assets to affiliates	613	700
Proceeds from the sale of assets to third parties	137	22
Proceeds from property insurance claims	2,944	—
Net cash used in investing activities	(952,824)	(371,878)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	530,000	769,694
Repayments of debt	(290,000)	(520,000)
Increase (decrease) in outstanding checks	(1,314)	(2,938)
Proceeds from the issuance of common units, net of offering expenses	25,000	57,376
Proceeds from the issuance of Series A Preferred units, net of offering expenses	686,940	—
Distributions to unitholders [2]	(313,380)	(259,247)
Distributions to noncontrolling interest owner	(7,460)	(7,175)
Net contributions from (distributions to) Anadarko	(27,459)	(17,439)
Above-market component of swap extensions with Anadarko [2]	16,365	—
Net cash provided by (used in) financing activities	618,692	20,271
Net increase (decrease) in cash and cash equivalents	59,734	20,714
Cash and cash equivalents at beginning of period	98,033	67,054
Cash and cash equivalents at end of period	$157,767	$87,768
Supplemental disclosures		
Acquisition of DBJV from Anadarko	$(159,524)	$174,276

Net distributions to (contributions from) Anadarko of other assets	354	4,540
Interest paid, net of capitalized interest	53,973	42,165
Taxes paid (reimbursements received)	67	(138)

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

(2) See Note 5.

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 is a growth-oriented Delaware master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007 to acquire, own, develop and operate midstream energy assets.
For purposes of these consolidated financial statements, the "Partnership" refers to Western Gas Partners, LP and its subsidiaries. The Partnership's general partner, Western Gas Holdings, LLC (the "general partner"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation in September 2012 to own the Partnership's general partner, as well as a significant limited partner interest in the Partnership (see Western Gas Equity Partners, LP below). WGP has no independent operations or material assets other than owning the partnership interests in WES (see Holdings of Partnership equity in Note 4). Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding the Partnership and the general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding the Partnership, but including equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." The "MGR assets" include the Red Desert complex, the Granger straddle plant and the interest in Rendezvous.
The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of June 30, 2016, the Partnership's assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	12	4	5	2
Treating facilities	13	12	—	3
Natural gas processing plants/trains	19	5	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas. In May 2016, the Partnership commenced operation of Train IV, a processing plant, at the DBM complex. The Partnership is constructing Train V, an additional processing plant at the DBM complex, with operations expected to commence during the second half of 2016. The Partnership has also made progress payments toward the construction of another cryogenic unit at the DBM complex (Train VI). The Partnership is evaluating when construction of Train VI will start and believe the earliest the plant will be online is the first quarter of 2018.

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

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

Basis of presentation. The following table outlines the Partnership’s ownership interests and the accounting method of consolidation used in the Partnership’s consolidated financial statements:

	Percentage Interest	
Equity investments [(1)]		
Fort Union	14.81	%
White Cliffs	10	%
Rendezvous	22	%
Mont Belvieu JV	25	%
TEP	20	%
TEG	20	%
FRP	33.33	%
Proportionate consolidation [(2)]		
Non-Operated Marcellus Interest systems	33.75	%
Anadarko-Operated Marcellus Interest systems	33.75	%
Newcastle system	50	%
DBJV system	50	%
Springfield system	50.1	%
Full consolidation		
Chipeta [(3)]	75	%

(1) Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. “Equity investment throughput” refers to the Partnership’s share of average throughput for these investments.

(2) The Partnership proportionately consolidates its associated share of the assets, liabilities, revenues and expenses attributable to these assets.

(3) The 25% interest in Chipeta Processing LLC (“Chipeta”) held by a third-party member is reflected within noncontrolling interest in the consolidated financial statements.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States (“GAAP”). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated.

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, using historical experience and other methods considered reasonable. 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 revisions become known. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated financial statements, and certain prior-period amounts have been reclassified to conform to the current-year presentation.

Certain information and note disclosures commonly 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 2015 Form 10-K, as filed with the SEC on February 25, 2016, certain sections of which were recast to reflect the results of the Springfield interest in the Partnership's Current Report on Form 8-K, as filed with the SEC on June 10, 2016. Management believes that the disclosures made are adequate to make the information not misleading.

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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. The term “Partnership assets” refers to the assets owned and interests accounted for under the equity method (see Note 7) by the Partnership as of June 30, 2016. Because Anadarko controls the Partnership through its ownership and control of WGP, which owns the Partnership’s entire general partner interest, each acquisition of Partnership assets from Anadarko has been 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 did not correlate to the total acquisition price paid by the Partnership. Further, after an acquisition of Partnership assets from Anadarko, the Partnership may be required to recast its financial statements to include the activities of such Partnership assets from the date of common control. See Note 2.

For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership’s 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 the Partnership had owned the Partnership assets during the periods reported. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership’s acquisition of the Partnership assets is not allocated to the limited partners.

Insurance recoveries. Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable and result in property damage insurance recovery. Amounts the Partnership receives from insurance carriers are net of any deductibles related to the covered event. The Partnership records a receivable from insurance to the extent it recognizes a loss from an involuntary conversion event and the likelihood of recovering such loss is deemed probable. To the extent that any of the Partnership’s insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. The Partnership recognizes gains on involuntary conversions when the amount received from insurance exceeds the net book value of the retired asset(s). In addition, the Partnership does not recognize a gain related to insurance recoveries until all contingencies related to such proceeds have been resolved, that is, a non-refundable cash payment is received from the insurance carrier or the Partnership has a binding settlement agreement with the carrier that clearly states that a non-refundable payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, in the consolidated balance sheets and presented as capital expenditures in the Partnership’s consolidated statements of cash flows. With respect to business interruption insurance claims, the Partnership recognizes income only when non-refundable cash proceeds are received from insurers, which are presented in the Partnership’s consolidated statements of operations as a component of Operating income (loss).

On December 3, 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. The majority of the damage from the incident was to the liquid handling facilities and the amine treating units at the inlet of the complex. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains but is expected to be returned to service by the end of 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. As of June 30, 2016, and December 31, 2015, the consolidated balance sheets include receivables of $44.2 million and $49.0 million, respectively, for a property insurance claim related to the incident at the DBM complex. As of June 30, 2016, the Partnership had received $5.5 million in cash proceeds from insurers related to the incident at the DBM complex, including $2.6 million in proceeds from business interruption insurance claims and $2.9 million in proceeds from property insurance claims.

Recently issued accounting standards. The Financial Accounting Standards Board recently issued the following Accounting Standards Updates (“ASUs”):

ASU 2016-02, Leases (Topic - 842). This ASU requires the lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet and disclose key information about their leasing transactions. This ASU is effective for annual and interim periods beginning in 2019. The Partnership is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

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

ASU 2015-06, Earnings Per Share (Topic - 260)—Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions. This ASU provides guidance for the presentation of historical earnings per unit for MLPs that apply the two-class method of calculating earnings per unit. When a general partner transfers or "drops down" net assets to an MLP, the transaction is accounted for as a transaction between entities under common control, and the statements of operations are adjusted retrospectively to reflect the transaction. This ASU specifies that the historical earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner, and the previously reported earnings per unit of the limited partners should not change as a result of the dropdown transaction. The ASU also requires additional disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs for purposes of computing earnings per unit under the two-class method. The Partnership applies the two-class method of calculating earnings per unit as described above (including the allocation of pre-acquisition net income (loss) to the general partner), and discloses the rights to earnings (losses) noted above. As such, there was no impact to the Partnership's consolidated financial statements upon adoption of this ASU on January 1, 2016.

ASU 2015-03, Interest—Imputation of Interest (Subtopic 835-30)—Simplifying the Presentation of Debt Issuance Costs and ASU 2015-15, Interest—Imputation of Interest (Subtopic 835-30)—Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements. These ASUs require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Partnership adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption resulted in a reclassification that reduced Other assets and Long-term debt by $16.7 million on the Partnership's consolidated balance sheet at December 31, 2015. See Note 9.

ASU 2015-02, Consolidation (Topic 810)—Amendments to the Consolidation Analysis. This ASU amends existing requirements applicable to reporting entities that are required to evaluate consolidation of a legal entity under the variable interest entity ("VIE") or voting interest entity models. The provisions will affect how limited partnerships and similar entities are assessed for consolidation, including an additional requirement that a limited partnership will be a VIE unless the limited partners have either substantive kick-out or participating rights over the general partner. The Partnership evaluated the impact of the adoption of this ASU on its consolidated financial statements and determined it does not have any entities for which it is the primary beneficiary for accounting and disclosure purposes. As such, the adoption of this ASU on January 1, 2016, did not impact the Partnership's consolidated financial statements.

ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU supersedes current revenue recognition requirements. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Partnership is required to adopt the new standard in the first quarter of 2018 using one of two retrospective application methods. The Partnership is continuing to evaluate the provisions of this ASU and has not determined the impact this standard may have on its consolidated financial statements and related disclosures or decided upon the method of adoption.

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2. ACQUISITIONS AND DIVESTITURES

The following table presents the acquisitions completed by the Partnership during 2016 and 2015, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Deferred Purchase Price Obligation - Anadarko	Borrowings	Common Units Issued	Series A Preferred Units
DBJV (1)	03/02/2015	100 %	$ 174,276	$ —	—	—
Springfield (2)	03/14/2016	100 %	—	247,500	2,089,602	14,030,611

(1) The Partnership acquired Delaware Basin JV Gathering LLC ("DBJV") from Anadarko. DBJV owns a 50% interest in a gathering system and related facilities. The DBJV gathering system and related facilities (the "DBJV system") are located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties, Texas. The Partnership will make a cash payment on March 31, 2020, to Anadarko as consideration for the acquisition of DBJV. At the acquisition date, the Partnership estimated the future payment would be $282.8 million, the net present value of which was $174.3 million. For further information, including revisions to the estimated future payment, see DBJV acquisition—deferred purchase price obligation - Anadarko below.

(2) The Partnership acquired Springfield Pipeline LLC ("Springfield") from Anadarko for $750.0 million, consisting of $712.5 million in cash and the issuance of 1,253,761 of the Partnership's common units. Springfield owns a 50.1% interest in an oil gathering system and a gas gathering system, such interest being referred to in this report as the "Springfield interest." The Springfield oil and gas gathering systems (collectively, the "Springfield system") are located in Dimmit, La Salle, Maverick and Webb Counties in South Texas. The Partnership financed the cash portion of the acquisition through: (i) borrowings of $247.5 million on the Partnership's senior unsecured revolving credit facility ("RCF"), (ii) the issuance of 835,841 of the Partnership's common units to WGP and (iii) the issuance of Series A Preferred units to private investors. See Note 4 for further information regarding the Series A Preferred units.

Springfield acquisition. Because the acquisition of Springfield was a transfer of net assets between entities under common control, the Partnership's historical financial statements and operational data previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the Springfield interest as if the Partnership owned Springfield for all periods presented. The consolidated financial statements for periods prior to the Partnership's acquisition of Springfield 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 Springfield during the periods reported.

The following table presents the impact of the Springfield interest on Revenues and other and Net income (loss) as presented in the Partnership's historical consolidated statements of operations:

	Three Months Ended June 30, 2015			
thousands	Partnership Historical	Springfield Interest	Eliminations	Combined
Revenues and other	$416,572	$ 49,438	$ (17)	$465,993
Net income (loss)	116,440	18,719	—	135,159

Six Months Ended June 30, 2015

thousands	Partnership Historical	Springfield Interest	Eliminations	Combined
Revenues and other	$804,981	$ 98,051	$ (33)	$902,999
Net income (loss)	(60,124)	42,016	—	(18,108)

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2. ACQUISITIONS AND DIVESTITURES (CONTINUED)

DBJV acquisition - deferred purchase price obligation - Anadarko. The consideration to be paid by the Partnership for the acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. The cash payment will be equal to (a) eight multiplied by the average of the Partnership's share in the Net Earnings (see definition below) of DBJV for the calendar years 2018 and 2019, less (b) the Partnership's share of all capital expenditures incurred for DBJV between March 1, 2015, and February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. As of the acquisition date, the estimated future payment obligation (based on management's estimate of the Partnership's share of forecasted Net Earnings and capital expenditures for DBJV) was $282.8 million, which had a net present value of $174.3 million, using a discount rate of 10%. As of June 30, 2016, the Partnership recognized a $241.1 million decrease in the estimated future payment obligation, resulting in a net present value of this obligation of $29.2 million, calculated using a discounted cash flow model with a 10% discount rate. The reduction in the value of the deferred purchase price obligation is primarily due to revisions reflecting a decrease in the Partnership's estimate of 2018 and 2019 Net Earnings and an increase in the Partnership's estimate of aggregate capital expenditures to be incurred by DBJV through February 29, 2020.

The following table summarizes the financial statement impact of the Deferred purchase price obligation - Anadarko:

	Deferred purchase price obligation - Anadarko	Estimated future payment obligation
Balance at March 2, 2015 – Acquisition date	$174,276	$282,807
Accretion expense (1)	14,398	
Balance at December 31, 2015	188,674	
Accretion expense (1)	4,537	
Balance at March 31, 2016	193,211	
Accretion revision (2)	(15,461)	
Revision to Deferred purchase price obligation – Anadarko (3)	(148,600)	
Balance at June 30, 2016	$29,150	$41,666

(1) Accretion expense was recorded as a charge to Interest expense on the consolidated statements of operations.
(2) Interest expense on the consolidated statements of operations includes financing-related accretion revisions of $15.5 million and $10.9 million for the three and six months ended June 30, 2016, respectively.
(3) Recorded as revisions within Common units on the consolidated balance sheets and consolidated statement of equity and partners' capital.

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3. PARTNERSHIP DISTRIBUTIONS

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

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2015			
March 31	$ 0.725	$ 133,203	May 2015
June 30	0.750	139,736	August 2015
September 30	0.775	146,160	November 2015
December 31	0.800	152,588	February 2016
2016			
March 31	$ 0.815	$ 158,905	May 2016
June 30 (1)	0.830	162,827	August 2016

(1) On July 20, 2016, the Board of Directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders of $0.830 per unit, or $162.8 million in aggregate, including incentive distributions, but excluding distributions on Class C units (see Class C unit distributions below) and Series A Preferred units (see Series A Preferred unit distributions below). The cash distribution is payable on August 12, 2016, to unitholders of record at the close of business on August 1, 2016.

Class C unit distributions. The Class C units receive quarterly distributions at a rate equivalent to the Partnership's common units. The distributions are paid in the form of additional Class C units ("PIK Class C units") until the scheduled conversion date on December 31, 2017 (unless earlier converted), and the Class C units are disregarded with respect to distributions of the Partnership's available cash until they are converted to common units. The number of additional PIK Class C units to be issued in connection with a distribution payable on the Class C units is determined by dividing the corresponding distribution attributable to the Class C units by the volume-weighted-average price of the Partnership's common units for the ten days immediately preceding the payment date for the common unit distribution, less a 6% discount. The Partnership records the PIK Class C unit distributions at fair value at the time of issuance. This Level 2 fair value measurement uses the Partnership's unit price as a significant input in the determination of the fair value. On May 13, 2016, the Partnership distributed 210,562 PIK Class C units to APC Midstream Holdings, LLC ("AMH"), the holder of the Class C units, for the quarterly distribution period ended March 31, 2016, and on February 11, 2016, the Partnership distributed 323,584 PIK Class C units to

AMH for the quarterly distribution period ended December 31, 2015.

Series A Preferred unit distributions. As further described in Note 4, the Partnership issued Series A Preferred units representing limited partner interests in the Partnership to private investors in March 2016 and April 2016. The Series A Preferred unitholders receive quarterly distributions in cash equal to $0.68 per Series A Preferred unit, subject to certain adjustments. The holders of the Series A Preferred units are entitled to certain rights that are senior to the rights of holders of common and Class C units, such as rights to distributions and rights upon liquidation of the Partnership. No payment or distribution on any junior equity security of the Partnership, including common and Class C units, for any quarter is permitted prior to the payment in full of the Series A Preferred unit distribution (including any outstanding arrearages). For the quarter ended June 30, 2016, the Series A Preferred unitholders will receive an aggregate cash distribution of $14.1 million comprised of a quarterly per unit distribution prorated for the 77-day period 7,892,220 Series A Preferred units were outstanding during the second quarter of 2016 and a full quarterly per unit distribution on 14,030,611 Series A Preferred units. For the quarter ended March 31, 2016, the Series A Preferred unitholders received an aggregate cash distribution of $1.9 million, based on the quarterly per unit distribution prorated for the 18-day period 14,030,611 Series A Preferred units were outstanding during the first quarter of 2016. See Note 4 for further discussion of the Series A Preferred units.

4. EQUITY AND PARTNERS' CAPITAL

Equity offerings. Pursuant to the Partnership's registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of common units ("$500.0 million COP"), during the year ended December 31, 2015, the Partnership issued 873,525 common units, at an average price of $66.61, generating proceeds of $57.4 million (net of $0.8 million for the underwriting discount and other offering expenses). Net proceeds were used for general partnership purposes, including funding capital expenditures. Gross proceeds generated during the year ended December 31, 2015, were $58.2 million. Commissions paid during the year ended December 31, 2015, were $0.6 million. The Partnership issued no common units under the $500.0 million COP during the six months ended June 30, 2016.

Class C units. In connection with the closing of the DBM acquisition in November 2014, the Partnership issued 10,913,853 Class C units to AMH at a price of $68.72 per unit, generating proceeds of $750.0 million, pursuant to a Unit Purchase Agreement ("UPA") with Anadarko and AMH. All outstanding Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. The Class C units were issued to partially fund the acquisition of DBM, and the UPA contains an optional redemption feature that provides the Partnership the ability to redeem up to $150.0 million of the Class C units within 10 days of the receipt of cash proceeds from an entity that is not an affiliate of the Partnership or AMH, if these cash proceeds were in relation to (i) the assets of DBM, (ii) the equity interests in DBM or (iii) the equity interests in a subsidiary of the Partnership that owns a majority of the outstanding equity interests in DBM. As of June 30, 2016, no such proceeds had been received, and no Class C units had been redeemed.
The Class C units were issued at a discount to the then-current market price of the common units into which they are convertible. This discount, totaling $34.8 million, represents a beneficial conversion feature, and at issuance, it was reflected as an increase in common unitholders' capital and a decrease in Class C unitholder capital to reflect the fair value of the Class C units at issuance. The beneficial conversion feature is considered a non-cash distribution that will be recognized from the date of issuance through the date of conversion, resulting in an increase in Class C unitholder capital and a decrease in common unitholders' capital as amortized. The beneficial conversion feature is amortized assuming a conversion date of December 31, 2017, using the effective yield method. The impact of the beneficial conversion feature amortization is also included in the calculation of earnings per unit.

Series A Preferred units. In connection with the closing of the Springfield acquisition on March 14, 2016, the Partnership issued 14,030,611 Series A Preferred units (the "March 2016 Series A units") to private investors for a cash purchase price of $32.00 per unit, generating proceeds of $440.0 million (net of fees and expenses, including a 2.0% transaction fee paid to the private investors). In April 2016, the Partnership issued an additional 7,892,220 Series A Preferred units (the "April 2016 Series A units") pursuant to the full exercise of an option granted in connection with the March 2016 Series A units issuance, generating net proceeds of $246.9 million. The Series A Preferred unitholders may convert the Series A Preferred units into common units on a one-for-one basis at any time after the second anniversary of the issuance date, in whole or in part, subject to certain conversion thresholds. Similarly, the Partnership may convert the Series A Preferred units at any time after the third anniversary of the issuance date, in whole or in part, if the closing price of the Partnership's common units is greater than $48.00 per common unit for 20 of the 30 preceding trading days, and subject to other certain conversion thresholds. In addition, upon certain events involving a change of control, the Series A Preferred unitholders may elect on an individual basis, subject to certain conditions, to (i) convert their Series A Preferred units to common units at the then applicable conversion rate, (ii) if the Partnership is not the surviving entity (or if the Partnership is the surviving entity, but its common units will cease to be listed), require the Partnership to use commercially reasonable efforts to cause the surviving entity in any such transaction to issue a substantially equivalent security (or convert into common units based on a specified formula, if the Partnership is unable to cause such substantially equivalent securities to be issued), (iii) if the Partnership is the surviving entity, continue to hold their Series A Preferred units, or (iv) require the Partnership to redeem the Series A Preferred units at a price per Series A Preferred unit of $32.32, plus accrued and unpaid distributions to be paid in cash or common units at the discretion of the Partnership.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

The Series A Preferred unitholders will vote on an as-converted basis with the Partnership's common unitholders and will have certain other class voting rights with respect to any amendment to the partnership agreement that would adversely affect any rights, preferences or privileges of the Series A Preferred unitholders. In connection with the issuance of the Series A Preferred units, the Partnership entered into a Registration Rights Agreement (the "Registration Rights Agreement") with the Series A Preferred unit purchasers relating to the registered resale of the common units representing limited partner interests in the Partnership issuable upon conversion of the Series A Preferred units. Pursuant to the Registration Rights Agreement, the Partnership is required to use its commercially reasonable efforts to file and maintain a registration statement for the resale of the converted Series A Preferred units, with such registration statement to become effective no later than March 2018.

The March 2016 Series A units and the April 2016 Series A units were issued at a discount to the then-current market price of the common units into which they are convertible. The discount on the March 2016 Series A units, totaling \$21.7 million, represents a beneficial conversion feature, and on the date the Preferred Unit Purchase Agreement was signed (the "commitment date"), it was reflected as an increase in common unitholders' capital and a decrease in Series A Preferred unitholders' capital to reflect the fair value of the March 2016 Series A units on the commitment date. The discount on the April 2016 Series A units, totaling \$71.7 million, also represents a beneficial conversion feature and on the date the option to purchase additional Series A units was exercised (the "notice date"), it was reflected as an increase in common unitholders' capital and a decrease in Series A Preferred unitholders' capital to reflect the fair value of the April 2016 Series A units on the notice date. The beneficial conversion features are considered non-cash distributions that will be recognized from each issuance date through the date of earliest conversion, resulting in an increase in Series A Preferred unitholders' capital and a decrease in common unitholders' capital as amortized. The beneficial conversion features are amortized assuming a conversion date of March 14, 2018 for the March 2016 Series A units and a conversion date of April 15, 2018 for the April 2016 Series A units, using the effective yield method.

Partnership interests. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."

The following table summarizes the common, Class C, Series A Preferred and general partner units issued during the six months ended June 30, 2016:

	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Total
Balance at December 31, 2015	128,576,965	11,411,862	—	2,583,068	142,571,895
PIK Class C units	—	534,146	—	—	534,146
Springfield acquisition	2,089,602	—	14,030,611	—	16,120,213
April 2016 Series A units	—	—	7,892,220	—	7,892,220
Long-Term Incentive Plan award vestings	5,403	—	—	—	5,403
Balance at June 30, 2016	130,671,970	11,946,008	21,922,831	2,583,068	167,123,877

4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Holdings of Partnership equity. As of June 30, 2016, WGP held 50,132,046 common units, representing a 30.0% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,583,068 general partner units, representing a 1.5% general partner interest in the Partnership, and 100% of the IDRs. As of June 30, 2016, other subsidiaries of Anadarko held 2,011,380 common units and 11,946,008 Class C units, representing an aggregate 8.4% limited partner interest in the Partnership. As of June 30, 2016, the public held 78,528,544 common units, representing a 47.0% limited partner interest in the Partnership and private investors held 21,922,831 Series A Preferred units, representing a 13.1% limited partner interest in the Partnership.

Net income (loss) per unit for common units. Net income (loss) attributable to Western Gas Partners, LP earned on and subsequent to the date of the acquisition of the Partnership assets, net of distributions on the Series A Preferred units and amortization of the Series A Preferred unit beneficial conversion features (see Series A Preferred units above), is allocated to the general partner, the common unitholders and the Class C unitholder, in accordance with their respective weighted-average ownership percentages (exclusive of the Series A Preferred unit limited partnership interest) and, when applicable, giving effect to incentive distributions allocable to the general partner. The allocable limited partners' interest in net income (loss) is also net of amortization of the beneficial conversion feature related to the Class C units (see Class C units above) and is allocated between the common and Class C unitholders by applying the provisions of the partnership agreement that govern actual cash distributions and capital account allocations, as if all earnings for the period had been distributed. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners for purposes of calculating net income (loss) per common unit.
Basic net income (loss) per common unit is calculated by dividing the limited partners' interest in net income (loss) attributable to common unitholders 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 Series A Preferred units are not considered a participating security as they only have distribution rights up to the specified per-unit quarterly distribution and have no rights to the Partnership's undistributed earnings. Because the Class C units participate in distributions with common units according to a predetermined formula (see Note 3), they are considered a participating security and are included in the computation of earnings per unit pursuant to the two-class method. The Class C unit participation right results in a non-contingent transfer of value each time the Partnership declares a distribution. Diluted net income (loss) per common unit is calculated by dividing the sum of (i) the limited partners' interest in net income (loss) attributable to common units adjusted for distributions on the Series A Preferred units and a reallocation of the limited partners' interest in net income (loss) assuming conversion of the Series A Preferred units into common units, and (ii) the limited partners' interest in net income (loss) allocable to the Class C units as a participating security, by the sum of the weighted-average number of common units outstanding plus the dilutive effect of (i) the weighted-average number of outstanding Class C units and (ii) the weighted-average number of common units outstanding assuming conversion of the Series A Preferred units.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

The following table illustrates the Partnership's calculation of net income (loss) per unit for common units:

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands except per-unit amounts	2016	2015	2016	2015
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Pre-acquisition net (income) loss allocated to Anadarko	—	(18,719)	(11,326)	(43,758)
Series A Preferred units interest in net (income) loss [1]	(23,121)	—	(25,450)	—
General partner interest in net (income) loss	(58,381)	(45,971)	(113,781)	(83,148)
Common and Class C limited partners' interest in net income (loss)	$83,019	$67,653	$130,024	$(151,056)
Net income (loss) allocable to common units [1]	$71,622	$59,119	$111,184	$(146,139)
Net income (loss) allocable to Class C units [1]	11,397	8,534	18,840	(4,917)
Common and Class C limited partners' interest in net income (loss)	$83,019	$67,653	$130,024	$(151,056)
Net income (loss) per unit				
Common units – basic and diluted [2]	$0.55	$0.46	$0.86	$(1.14)
Weighted-average units outstanding				
Common units – basic and diluted	130,669	128,481	129,830	128,111
Excluded due to anti-dilutive effect:				
Class C units	11,849	11,023	11,719	10,981
Series A Preferred units assuming conversion to common units	20,709	—	11,742	—

(1) Adjusted to reflect amortization of the beneficial conversion features.
(2) The impact of Class C units and the conversion of Series A Preferred units would be anti-dilutive.

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 and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operation 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.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition 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. 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. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.

Note receivable - Anadarko and Deferred purchase price obligation - Anadarko. Concurrently 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 $301.5 million and $252.3 million at June 30, 2016, and December 31, 2015, 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.
The consideration to be paid by the Partnership to Anadarko for the March 2015 acquisition of DBJV consists of a cash payment due on March 31, 2020. See Note 2 and Note 9.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a majority of the 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. The outstanding commodity price swap agreements for the Hugoton system, MGR assets and DJ Basin complex expire in December 2016. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be measured at fair value.
Below is a summary of the fixed price ranges on all of the Partnership's outstanding commodity price swap agreements as of June 30, 2016:

per barrel except natural gas	2016	
Ethane	$18.41	−23.11
Propane	47.08	−52.90
Isobutane	62.09	−73.89
Normal butane	54.62	−64.93
Natural gasoline	72.88	−81.68

Condensate	76.47	− 81.68
Natural gas (per MMBtu)	4.87	− 5.96

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

The following table summarizes gains and losses upon settlement of commodity price swap agreements recognized in the consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2016	2015	2016	2015
Gains (losses) on commodity price swap agreements related to sales: [1]				
Natural gas sales	$5,202	$22,344	$12,243	$33,326
Natural gas liquids sales	20,480	38,297	40,550	82,729
Total	25,682	60,641	52,793	116,055
Losses on commodity price swap agreements related to purchases [2]	(16,913)	(41,720)	(35,784)	(75,899)
Net gains (losses) on commodity price swap agreements	$8,769	$18,921	$17,009	$40,156

(1) Reported in affiliate Natural gas and natural gas liquids sales in the consolidated statements of operations in the period in which the related sale is recorded.
(2) Reported in Cost of product in the consolidated statements of operations in the period in which the related purchase is recorded.

DJ Basin complex and Hugoton system swap extensions. On June 25, 2015, the Partnership extended its commodity price swap agreements with Anadarko for the DJ Basin complex from July 1, 2015, through December 31, 2015, and for the Hugoton system from October 1, 2015, through December 31, 2015. The table below summarizes the swap prices for the extension period compared to the forward market prices as of the agreement date, June 25, 2015.

	DJ Basin Complex		Hugoton System	
per barrel except natural gas	2015 Swap Prices	Market Prices [1]	2015 Swap Prices	Market Prices [1]
Ethane	$18.41	$ 1.96	—	—
Propane	47.08	13.10	—	—
Isobutane	62.09	19.75	—	—
Normal butane	54.62	18.99	—	—
Natural gasoline	72.88	52.59	—	—
Condensate	76.47	52.59	$78.61	$ 32.56
Natural gas (per MMBtu)	5.96	2.75	5.50	2.74

(1) Represents the New York Mercantile Exchange (“NYMEX”) forward strip price as of June 25, 2015, adjusted for product specification, location, basis and, in the case of NGLs, transportation and fractionation costs.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

On December 8, 2015, the commodity price swap agreements with Anadarko for the DJ Basin complex and Hugoton system were further extended from January 1, 2016, through December 31, 2016. The table below summarizes the swap prices for the extension period compared to the forward market prices as of the agreement date, December 8, 2015.

	DJ Basin Complex		Hugoton System	
per barrel except natural gas	2016 Swap Prices	Market Prices (1)	2016 Swap Prices	Market Prices (1)
Ethane	$18.41	$ 0.60	—	—
Propane	47.08	10.98	—	—
Isobutane	62.09	17.23	—	—
Normal butane	54.62	16.86	—	—
Natural gasoline	72.88	26.15	—	—
Condensate	76.47	34.65	$78.61	$ 18.81
Natural gas (per MMBtu)	5.96	2.11	5.50	2.12

(1) Represents the NYMEX forward strip price as of December 8, 2015, adjusted for product specification, location, basis and, in the case of NGLs, transportation and fractionation costs.

Revenues or costs attributable to volumes settled during the respective extension period, at the applicable market price in the above tables, will be recognized in the consolidated statements of operations. The Partnership will also record a capital contribution from Anadarko in the Partnership's consolidated statement of equity and partners' capital for the amount by which the swap price exceeds the applicable market price in the above tables. For the six months ended June 30, 2016, the capital contribution from Anadarko was $16.4 million.

Gathering and processing agreements. The Partnership has significant gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The Partnership's gathering, treating and transportation throughput (excluding equity investment throughput) attributable to natural gas production owned or controlled by Anadarko was 39% and 38% for the three and six months ended June 30, 2016, respectively, and 56% for the three and six months ended June 30, 2015. The Partnership's processing throughput (excluding equity investment throughput) attributable to natural gas production owned or controlled by Anadarko was 55% and 58% for the three and six months ended June 30, 2016, respectively, and 52% for the three and six months ended June 30, 2015. The Partnership's gathering, treating and transportation throughput (excluding equity investment throughput) attributable to crude/NGL production owned or controlled by Anadarko was 64% for the three and six months ended June 30, 2016, and 100% for the three and six months ended June 30, 2015. Prior to January 1, 2016, Springfield's contracts were with a subsidiary of Anadarko who contracted with third parties. Effective January 1, 2016, Springfield's contracts are with both a subsidiary of Anadarko and third parties directly.

Commodity purchase and sale agreements. The Partnership sells a significant amount of its natural gas, condensate and NGLs to Anadarko Energy Services Company ("AESC"), Anadarko's marketing affiliate. In addition, the Partnership purchases natural gas, condensate and NGLs from AESC pursuant to purchase agreements. The Partnership's purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Acquisitions from Anadarko. On March 14, 2016, the Partnership acquired Springfield from Anadarko, and on March 2, 2015, the Partnership acquired DBJV from Anadarko. See Note 2 for further information on these acquisitions.

WES LTIP. The general partner awards phantom units under the Western Gas Partners, LP 2008 Long-Term Incentive Plan ("WES LTIP") primarily to its independent directors, but also from time to time to its executive officers and Anadarko employees performing services for the Partnership. The phantom units awarded to the independent directors vest one year from the grant date, while all other awards are subject to graded vesting over a three-year service period. Compensation expense is recognized over the vesting period and was $0.1 million for each of the three months ended June 30, 2016 and 2015, and $0.2 million for each of the six months ended June 30, 2016 and 2015.

WGP LTIP and Anadarko Incentive Plans. General and administrative expenses included $1.1 million and $2.4 million for the three and six months ended June 30, 2016, respectively, and $1.0 million and $2.0 million for the three and six months ended June 30, 2015, respectively, of equity-based compensation expense, allocated to the Partnership by Anadarko, for awards granted to the executive officers of the general partner and other employees under the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan ("WGP LTIP") and the Anadarko Petroleum Corporation 2008 and 2012 Omnibus Incentive Compensation Plans (referred to collectively as the "Anadarko Incentive Plans"). Of this amount, $2.1 million is reflected as a contribution to partners' capital in the Partnership's consolidated statement of equity and partners' capital for the six months ended June 30, 2016.

Equipment purchases and sales. The following table summarizes the Partnership's purchases from and sales to Anadarko of pipe and equipment:

	Six Months Ended June 30,			
	2016	2015	2016	2015
thousands	Purchases		Sales	
Cash consideration	$2,699	$9,056	$613	$700
Net carrying value	2,328	4,182	596	366
Partners' capital adjustment	$371	$4,874	$17	$334

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Summary of affiliate transactions. The following table summarizes material affiliate transactions. See Note 2 for discussion of affiliate acquisitions and related funding.

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2016	2015	2016	2015
Revenues and other [1]	$302,405	$321,411	$574,989	$628,339
Equity income, net – affiliates [1]	19,693	18,941	36,507	37,161
Cost of product [1]	22,145	53,062	46,725	96,957
Operation and maintenance [2]	17,661	19,854	35,636	36,671
General and administrative [3]	9,169	8,060	18,121	16,195
Operating expenses	48,975	80,976	100,482	149,823
Interest income [4]	4,225	4,225	8,450	8,450
Interest expense [5]	(15,461)	4,190	(10,924)	5,610
Proceeds from the issuance of common units, net of offering expenses [6]	—	—	25,000	—
Distributions to unitholders [7]	94,909	76,353	184,678	148,048
Above-market component of swap extensions with Anadarko	9,552	—	16,365	—

(1) Represents amounts earned or incurred on and subsequent to the date of acquisition of the Partnership assets, as well as amounts earned or incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets, recognized under gathering, treating or processing agreements, and purchase and sale agreements.

(2) Represents expenses incurred on and subsequent to the date of the 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.

(3) Represents general and administrative expense incurred on and subsequent to the date of the Partnership's acquisition of the Partnership assets, as well as a management services fee for reimbursement of expenses incurred by Anadarko for periods prior to the acquisition of the Partnership assets by the Partnership. These amounts include equity-based compensation expense allocated to the Partnership by Anadarko (see WES LTIP and WGP LTIP and Anadarko Incentive Plans within this Note 5).

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

(5) For the three and six months ended June 30, 2016, includes accretion revisions to the Deferred purchase price obligation - Anadarko (see Note 2 and Note 9).

(6) Represents proceeds from the issuance of 835,841 common units to WGP as partial funding for the acquisition of Springfield (see Note 2).

(7) Represents distributions paid under the partnership agreement (see Note 3 and Note 4).

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

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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	June 30, 2016	December 31, 2015
Land	n/a	$3,946	$ 3,744
Gathering systems	3 to 47 years	6,409,489	6,061,004
Pipelines and equipment	15 to 45 years	135,319	136,290
Assets under construction	n/a	239,617	329,887
Other	3 to 40 years	29,803	25,853
Total property, plant and equipment		6,818,174	6,556,778
Accumulated depreciation		1,816,030	1,697,999
Net property, plant and equipment		$5,002,144	$ 4,858,779

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.
As of June 30, 2016, net property, plant and equipment includes impairments of $8.9 million, primarily due to an impairment of $6.1 million at the Newcastle system. This asset was impaired to its estimated fair value of $3.1 million, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment. Also during this period, the Partnership recognized impairments of $2.4 million, primarily related to the abandonment of compressors at the MIGC system.

7. EQUITY INVESTMENTS

The following table presents the activity in the Partnership's equity investments for the six months ended June 30, 2016:

	Equity Investments							
thousands	Fort Union	White Cliffs	Rendezvous	Mont Belvieu JV	TEG	TEP	FRP	Total
Balance at December 31, 2015	$17,122	$50,439	$ 50,913	$117,089	$16,283	$194,803	$172,238	$618,887
Investment earnings (loss), net of amortization	(1,360)	7,164	949	12,686	343	7,766	8,959	36,507
Contributions	—	441	—	—	—	(580)	—	(139)
Distributions	—	(6,873)	(1,364)	(12,303)	(354)	(7,892)	(9,733)	(38,519)
Distributions in excess of cumulative earnings [(1)]	(3,354)	(2,100)	(1,541)	(172)	(188)	(2,918)	(338)	(10,611)
Balance at June 30, 2016	$12,408	$49,071	$ 48,957	$117,300	$16,084	$191,179	$171,126	$606,125

(1) Distributions in excess of cumulative earnings, classified as investing cash flows in the consolidated statements of cash flows, is calculated on an individual investment basis.

During the six months ended June 30, 2016, an impairment loss was recognized by the managing partner of Fort Union. The Partnership's 14.81% share of the impairment loss was $3.0 million, which was recorded in Equity income, net – affiliates in the consolidated statements of operations.

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8. COMPONENTS OF WORKING CAPITAL

A summary of accounts receivable, net is as follows:

thousands	June 30, 2016	December 31, 2015
Trade receivables, net	$177,507	$143,557
Other receivables, net	44,288	49,772
Total accounts receivable, net	$221,795	$193,329

A summary of other current assets is as follows:

thousands	June 30, 2016	December 31, 2015
Natural gas liquids inventory	$4,032	$ 2,403
Imbalance receivables	1,359	2,122
Prepaid insurance	300	2,296
Other	—	1,034
Total other current assets	$5,691	$ 7,855

A summary of accrued liabilities is as follows:

thousands	June 30, 2016	December 31, 2015
Accrued capital expenditures	$70,725	$61,454
Accrued plant purchases	27,149	16,425
Accrued interest expense	26,200	26,194
Short-term asset retirement obligations	2,713	3,677
Short-term remediation and reclamation obligations	1,136	1,136
Income taxes payable	1,127	770
Other	968	9,363
Total accrued liabilities	$130,018	$119,019

9. DEBT AND INTEREST EXPENSE

At June 30, 2016, the Partnership's debt consisted of 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes"), 3.950% Senior Notes due 2025 (the "2025 Notes"), and borrowings on the RCF.
The following table presents the Partnership's outstanding debt as of June 30, 2016, and December 31, 2015:

	June 30, 2016			December 31, 2015		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
2021 Notes	$500,000	$494,215	$529,064	$500,000	$493,711	$513,645
2022 Notes	670,000	668,532	658,273	670,000	668,432	595,744
2018 Notes	350,000	348,946	348,908	350,000	348,706	339,293
2044 Notes	400,000	389,783	384,252	400,000	389,707	321,499
2025 Notes	500,000	490,528	479,690	500,000	490,095	422,285
RCF	540,000	540,000	540,000	300,000	300,000	300,000
Total long-term debt	$2,960,000	$2,932,004	$2,940,187	$2,720,000	$2,690,651	$2,492,466

[1] Fair value is measured using the market approach and Level 2 inputs.

Debt activity. The following table presents the debt activity of the Partnership for the six months ended June 30, 2016:

thousands	Carrying Value
Balance at December 31, 2015	$ 2,690,651
RCF borrowings	530,000
Repayments of RCF borrowings	(290,000)
Other	1,353
Balance at June 30, 2016	$ 2,932,004

Senior Notes. At June 30, 2016, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.
In July 2016, the Partnership issued $500.0 million aggregate principal amount of 4.650% Senior Notes due 2026 (the "2026 Notes") which were offered at a price to the public of 99.796% of the face amount. Interest is paid semi-annually on January 1 and July 1 of each year. Proceeds (net of underwriting discount of $3.1 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the RCF.

Revolving credit facility. The interest rate on the RCF, which matures in February 2019, was 1.77% and 1.49% at June 30, 2016 and 2015, respectively. The facility fee rate was 0.20% at June 30, 2016 and 2015.
As of June 30, 2016, the Partnership had $540.0 million of outstanding borrowings, $4.9 million in outstanding letters of credit and $655.1 million available for borrowing under the RCF. At June 30, 2016, the Partnership was in compliance with all covenants under the RCF.
In April 2016, the Partnership repaid $250.0 million of outstanding borrowings under the RCF, $246.9 million of which was funded with the proceeds from the issuance of the April 2016 Series A unit issuance (see Note 4).

Interest rate agreements. In June 2016, the Partnership entered into a U.S. Treasury rate lock agreement to mitigate the risk of rising interest rates on existing variable-rate debt expected to be refinanced during the third quarter of 2016. The rate lock agreement was not designated as a cash flow hedge and was settled in June 2016 upon the offering of the 2026 Notes that closed in July 2016. The Partnership realized a loss of $0.2 million at settlement, which is included in

Other income (expense), net in the Partnership's consolidated statements of operations.

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9. DEBT AND INTEREST EXPENSE (CONTINUED)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2016	2015	2016	2015
Third parties				
Long-term debt	$28,281	$24,733	$56,099	$48,075
Amortization of debt issuance costs and commitment fees	1,545	1,374	3,075	2,666
Capitalized interest	(1,482)	(2,693)	(3,331)	(5,787)
Total interest expense – third parties	28,344	23,414	55,843	44,954
Affiliates				
Deferred purchase price obligation – Anadarko[(1)]	(15,461)	4,190	(10,924)	5,610
Total interest expense – affiliates	(15,461)	4,190	(10,924)	5,610
Interest expense	$12,883	$27,604	$44,919	$50,564

(1) See Note 2 for a discussion of the accretion and net present value of the Deferred purchase price obligation - Anadarko.

10. COMMITMENTS AND CONTINGENCIES

Litigation and legal proceedings. 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 the final disposition of which 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 June 30, 2016, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $38.3 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to the construction of Trains V and VI at the DBM complex and expansion projects at the DBJV system and the DJ Basin complex.

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, for which Anadarko charges the Partnership rent. The leases for the corporate offices and shared field offices extend through 2017 and 2018, respectively, and the lease for the warehouse extends through February 2017.
Rent expense associated with the office, warehouse and equipment leases was $8.4 million and $17.3 million for the three and six months ended June 30, 2016, respectively, and $8.5 million and $16.5 million for the three and six months ended June 30, 2015, respectively.

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

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included under Part I, Item 1 of this quarterly report, as well as our historical consolidated financial statements, and the notes thereto, which are included in Part II, Item 8 of our 2015 Form 10-K as filed with the SEC on February 25, 2016, certain sections of which were recast to reflect the results of the Springfield interest in our Current Report on Form 8-K, as filed with the SEC on June 10, 2016.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this Form 10-Q, and may from time to time make in other public filings, press releases and statements by management, forward-looking statements concerning our operations, economic performance and financial condition. These forward-looking statements include statements preceded by, followed by or that otherwise include the words “believes,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “target,” “goal,” “plans,” “objective,” similar expressions or variations on such expressions. These statements discuss future expectations, contain projections of results of operations or financial condition or include other “forward-looking” information. Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any 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:

- our ability to pay distributions to our unitholders;
- our and Anadarko’s assumptions about the energy market;
- future throughput, including Anadarko’s production, which is gathered or processed by or transported through our assets;
- our 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, demand for, and the price of, oil, natural gas, NGLs and related products or services;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;

- federal, state and local laws, including those that limit Anadarko’s and other producers’ hydraulic fracturing or other oil and natural gas operations;
- environmental liabilities;

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- legislative or regulatory changes, including changes affecting our status as a partnership for federal income tax purposes;
- changes in the financial or operational condition of Anadarko;
- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use our RCF;
- our ability to repay debt;
- our ability to mitigate exposure to the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts through the extension of our commodity price swap agreements with Anadarko, or otherwise;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- 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" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" included in our 2015 Form 10-K, certain sections of which were recast to reflect the results of the Springfield interest in our Current Report on Form 8-K, as filed with the SEC on June 10, 2016, in our quarterly reports on Form 10-Q and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this Form 10-Q could cause actual results to differ materially from those contained in any forward-looking statement. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to acquire, own, develop and operate midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas, and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of June 30, 2016, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	12	4	5	2
Treating facilities	13	12	—	3
Natural gas processing plants/trains	19	5	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

Significant financial and operational events during the six months ended June 30, 2016, included the following:

- We completed the acquisition of Springfield from Anadarko for cash and common unit consideration totaling $750.0 million. See Acquisitions and Divestitures below.

- In May 2016, the Partnership commenced operation of Train IV, a 200 MMcf/d processing plant at the DBM complex.

- We raised our distribution to $0.830 per unit for the second quarter of 2016, representing a 2% increase over the distribution for the first quarter of 2016 and an 11% increase over the distribution for the second quarter of 2015.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,870 MMcf/d and 3,825 MMcf/d for the three and six months ended June 30, 2016, respectively, representing a 12% and 11% decrease, respectively, compared to the same periods in 2015.

- Throughput for crude/NGL assets totaled 187 MBbls/d and 186 MBbls/d for the three and six months ended June 30, 2016, respectively, representing a 1% increase compared to the same periods in 2015.

- Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $0.84 per Mcf and $0.82 per Mcf for the three and six months ended June 30, 2016, respectively, representing a 15% and 14% increase, respectively, compared to the same periods in 2015.

- Adjusted gross margin for crude/NGL assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $2.03 per Bbl and $2.05 per Bbl for the three and six months ended June 30, 2016, respectively, representing a 3% and 5% increase, respectively, compared to the same periods in 2015.

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Significant Item Affecting Comparability. On December 3, 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. The majority of the damage was to the liquid handling facilities and the amine treating units at the inlet of the complex. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains but is expected to be returned to service by the end of 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. For ease of reference throughout the remainder of this Management's Discussion and Analysis, the damage to the processing facility and resulting lack of processing capacity and associated financial statement impact will be referred to as the "DBM outage." See Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

ACQUISITIONS AND DIVESTITURES

Acquisitions. The following table presents our acquisitions during 2016 and 2015, and identifies the funding sources for such acquisitions. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired		Deferred Purchase Price Obligation - Anadarko	Borrowings	Common Units Issued	Series A Preferred Units
DBJV [1]	03/02/2015	100	%	$ 174,276	$ —	—	—
Springfield [2]	03/14/2016	100	%	—	247,500	2,089,602	14,030,611

(1) We acquired DBJV from Anadarko. DBJV owns a 50% interest in the DBJV system. We will make a cash payment on March 31, 2020, to Anadarko as consideration for the acquisition of DBJV. At the acquisition date, we estimated the future payment would be $282.8 million, the net present value of which was $174.3 million. For further information, including revisions to the estimated future payment, see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

(2) We acquired Springfield from Anadarko for $750.0 million, consisting of $712.5 million in cash and the issuance of 1,253,761 of our common units. Springfield owns a 50.1% interest in the Springfield system. We financed the cash portion of the acquisition through: (i) borrowings of $247.5 million on our RCF, (ii) the issuance of 835,841 of our common units to WGP and (iii) the issuance of Series A Preferred units to private investors. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q for a discussion of the Series A Preferred units.

Presentation of Partnership assets. The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method by us as of June 30, 2016. See Note 7—Equity Investments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. Because Anadarko controls us through its ownership and control of WGP, which owns the entire interest in our general partner, each of our acquisitions of Partnership assets from Anadarko has been 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 did not correlate to the total acquisition price paid by us. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control.

The historical financial statements and operational data previously filed with the SEC have been recast in this Form 10-Q to include the results attributable to the Springfield interest as if we owned Springfield for all periods presented. The consolidated financial statements for periods prior to our acquisition of Springfield 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 Springfield during the periods reported.

EQUITY OFFERINGS

Equity offerings. Pursuant to our $500.0 million COP, during the year ended December 31, 2015, we issued 873,525 common units, at an average price of $66.61, generating proceeds of $57.4 million (net of $0.8 million for the underwriting discount and other offering expenses), which were used for general partnership purposes, including funding capital expenditures. Gross proceeds generated during the year ended December 31, 2015, were $58.2 million. Commissions paid during the year ended December 31, 2015, were $0.6 million. We issued no common units under the $500.0 million COP during the six months ended June 30, 2016.

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Other equity offerings. In March 2016, we issued the March 2016 Series A units to private investors for a cash purchase price of $32.00 per unit, generating proceeds of $440.0 million (net of fees and expenses, including a 2.0% transaction fee paid to the private investors), which were used to fund a portion of the Springfield acquisition. In April 2016, we issued the April 2016 Series A units pursuant to the full exercise of an option granted in connection with the March 2016 Series A units issuance, generating net proceeds of $246.9 million, which were used to pay down amounts borrowed under our RCF in connection with the Springfield acquisition. See Note 4—Equity and Partners' Capital and Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

RESULTS OF OPERATIONS

OPERATING RESULTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2016	2015	2016	2015
Total revenues and other [(1)]	$428,664	$465,993	$811,805	$902,999
Equity income, net – affiliates	19,693	18,941	36,507	37,161
Total operating expenses [(1)]	272,691	314,221	518,611	891,774
Gain (loss) on divestiture and other, net	(1,907)	—	(2,539)	(6)
Proceeds from business interruption insurance claims [(2)]	2,603	—	2,603	—
Operating income (loss)	176,362	170,713	329,765	48,380
Interest income – affiliates	4,225	4,225	8,450	8,450
Interest expense	(12,883)	(27,604)	(44,919)	(50,564)
Other income (expense), net	(53)	71	71	142
Income (loss) before income taxes	167,651	147,405	293,367	6,408
Income tax (benefit) expense	326	12,246	6,959	24,516
Net income (loss)	167,325	135,159	286,408	(18,108)
Net income attributable to noncontrolling interest	2,804	2,816	5,827	6,042
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Key performance metrics [(3)]				
Adjusted gross margin attributable to Western Gas Partners, LP	$329,254	$326,797	$640,478	$629,447
Adjusted EBITDA attributable to Western Gas Partners, LP	250,565	245,548	481,664	465,510
Distributable cash flow	199,349	211,674	391,287	397,252

(1) Revenues and other include amounts earned from services provided to our affiliates, as well as from the sale of residue 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 Part I, Item 1 of this Form 10-Q.

(2) See Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

(3) Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow are defined under the caption Key Performance Metrics within this Item 2. For reconciliations of Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, see Key Performance Metrics within this Item 2.

For purposes of the following discussion, any increases or decreases “for the three months ended June 30, 2016” refer to the comparison of the three months ended June 30, 2016, to the three months ended June 30, 2015; any increases or decreases “for the six months ended June 30, 2016” refer to the comparison of the six months ended June 30, 2016, to the six months ended June 30, 2015; and any increases or decreases “for the three and six months ended June 30, 2016” refer to the comparison of these 2016 periods to the corresponding three and six month periods ended June 30, 2015.

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Throughput

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)						
Gathering, treating and transportation	1,508	1,920	(21)%	1,553	1,942	(20)%
Processing	2,320	2,465	(6)%	2,226	2,362	(6)%
Equity investment [1]	170	172	(1)%	178	169	5 %
Total throughput for natural gas assets	3,998	4,557	(12)%	3,957	4,473	(12)%
Throughput attributable to noncontrolling interest for natural gas assets	128	159	(19)%	132	161	(18)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,870	4,398	(12)%	3,825	4,312	(11)%
Throughput for crude/NGL assets (MBbls/d)						
Gathering, treating and transportation	59	74	(20)%	59	75	(21)%
Equity investment [2]	128	111	15 %	127	109	17 %
Total throughput for crude/NGL assets	187	185	1 %	186	184	1 %

(1) Represents our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput.
(2) Represents our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput, and our 33.33% share of average FRP throughput.

Natural gas assets

Gathering, treating and transportation throughput decreased by 412 MMcf/d and 389 MMcf/d for the three and six months ended June 30, 2016, respectively, primarily due to (i) the sale of the Dew and Pinnacle systems in July 2015, (ii) decreased throughput at the Bison facility due to volumes being diverted to a third-party treater and (iii) production declines in the areas around the Non-Operated Marcellus Interest systems.
Processing throughput decreased by 145 MMcf/d and 136 MMcf/d for the three and six months ended June 30, 2016, respectively, primarily due to the DBM outage, decreased throughput at the Chipeta complex due to decreased drilling activity in the Uinta Basin, production declines in the areas around the Red Desert and Granger complexes and lower volumes processed at the Granger straddle plant. These decreases were partially offset by increased production in the areas around the DJ Basin complex.
Equity investment throughput increased by 9 MMcf/d for the six months ended June 30, 2016, primarily due to volumes being diverted from the third-party Bison pipeline to the Fort Union system, which was partially offset by a decrease in volumes at the Rendezvous system due to production declines in the Jonah and Pinedale Anticline fields.

Crude/NGL assets

Gathering, treating and transportation throughput decreased by 15 MBbls/d and 16 MBbls/d for the three and six months ended June 30, 2016, respectively, primarily due to decreased throughput at the Springfield oil gathering system. Equity investment throughput increased by 17 MBbls/d and 18 MBbls/d for the three and six months ended June 30, 2016, respectively, primarily due to an increase in volumes on FRP as a result of increased production in the DJ Basin area.

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Gathering, Processing and Transportation Revenues

thousands except percentages	Three Months Ended June 30, 2016	2015	Inc/ (Dec)	Six Months Ended June 30, 2016	2015	Inc/ (Dec)
Gathering, processing and transportation revenues	$301,136	$290,900	4 %	$595,140	$561,168	6 %

Revenues from gathering, processing and transportation increased by $10.2 million and $34.0 million for the three and six months ended June 30, 2016, respectively, primarily due to increases of $26.4 million and $67.8 million, respectively, at the DJ Basin complex resulting from increased throughput and a higher processing fee. These increases were partially offset by decreases during the three and six months ended June 30, 2016, of (i) $7.6 million and $15.1 million, respectively, due to the sale of the Dew and Pinnacle systems in July 2015 and (ii) $5.9 million and $10.2 million, respectively, at the Springfield system due to decreased throughput. In addition, there was a decrease of $3.6 million at the Chipeta complex for the three months ended June 30, 2016, due to a decrease in throughput and there was a decrease of $8.9 million for the six months ended June 30, 2016, due to the DBM outage.

Natural Gas and Natural Gas Liquids Sales

thousands except percentages and per-unit amounts	Three Months Ended June 30, 2016	2015	Inc/ (Dec)	Six Months Ended June 30, 2016	2015	Inc/ (Dec)
Natural gas sales [(1)]	$44,366	$71,463	(38)%	$82,593	$133,654	(38)%
Natural gas liquids sales [(1)]	82,627	102,739	(20)%	132,956	206,220	(36)%
Total	$126,993	$174,202	(27)%	$215,549	$339,874	(37)%
Average price per unit [(1)]:						
Natural gas (per Mcf)	$2.09	$3.68	(43)%	$2.20	$3.64	(40)%
Natural gas liquids (per Bbl)	20.33	21.78	(7)%	19.69	24.41	(19)%

(1) Excludes amounts considered above market, with respect to our swap extensions at the DJ Basin complex and the Hugoton system beginning July 1, 2015, that are recorded as capital contributions in the statement of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

For the three and six months ended June 30, 2016 and 2015, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the Hugoton system, the MGR assets and the DJ Basin complex. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

The declines in natural gas sales of $27.1 million and $51.1 million for the three and six months ended June 30, 2016, respectively, were primarily due to decreases of (i) $13.2 million and $12.5 million, respectively, at the DJ Basin complex due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015, partially offset by an increase in volume (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q), (ii) $7.3 million and $26.3 million, respectively, due to the DBM outage and (iii) $4.8 million and $8.5 million, respectively, at the Hilight system due to a decrease in average price and volume.

The declines in NGLs sales of $20.1 million and $73.3 million for the three and six months ended June 30, 2016, respectively, were primarily due to decreases of (i) $15.0 million and $33.5 million, respectively, due to the DBM outage, (ii) $10.6 million and $21.0 million, respectively, at the MGR assets due to a decrease in volumes sold and (iii) $1.5 million and $6.7 million, respectively, at the Hilight system due to a decrease in volumes sold. The decline for the six months ended June 30, 2016, was also impacted by decreases of $5.2 million and $3.2 million at the DJ

Basin complex and Hugoton system, respectively, due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015 for the DJ Basin complex and October 1, 2015 for the Hugoton system (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q). The decrease for the three months ended June 30, 2016, was partially offset by an increase of $8.3 million at the DJ Basin complex due to an increase in volumes sold.

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Equity Income, Net – Affiliates

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
Equity income, net – affiliates	$19,693	$18,941	4 %	$36,507	$37,161	(2)%

For the three months ended June 30, 2016, equity income, net – affiliates increased by $0.8 million, primarily due to an increase in equity income from the Mont Belvieu JV due to increased volumes, partially offset by a decrease in equity income at the Fort Union system. For the six months ended June 30, 2016, equity income, net – affiliates decreased by $0.7 million, primarily due to our 14.81% share of an impairment loss determined by the managing partner of Fort Union, partially offset by increases in equity income from the TEFR Interests and the Mont Belvieu JV due to increased volumes.

Cost of Product and Operation and Maintenance Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
NGL purchases [1]	$50,056	$73,866	(32)%	$82,725	$138,767	(40)%
Residue purchases [1]	47,413	67,238	(29)%	86,398	135,959	(36)%
Other [1]	7,380	6,112	21 %	12,193	11,898	2 %
Cost of product	104,849	147,216	(29)%	181,316	286,624	(37)%
Operation and maintenance	75,173	77,837	(3)%	151,386	154,022	(2)%
Total cost of product and operation and maintenance expenses	$180,022	$225,053	(20)%	$332,702	$440,646	(24)%

(1) Excludes amounts considered above market, with respect to our swap extensions at the DJ Basin complex and the Hugoton system beginning July 1, 2015, that are recorded as capital contributions in the statement of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Cost of product expense for the three and six months ended June 30, 2016 and 2015, included the effects of commodity price swap agreements attributable to purchases for the Hugoton system, the MGR assets and the DJ Basin complex. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

NGL purchases decreased by $23.8 million and $56.0 million for the three and six months ended June 30, 2016, respectively, primarily due to decreases of (i) $11.3 million and $26.8 million, respectively, due to the DBM outage, (ii) $7.6 million and $14.1 million, respectively, at the Red Desert complex due to decreases in volumes and average swap prices, (iii) $2.0 million and $4.7 million, respectively, at the DJ Basin complex due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015, and (iv) $1.8 million and $5.6 million, respectively, at the Hilight system due to decreases in volumes and average prices. The decrease in NGL purchases for the six months ended June 30, 2016, was also impacted by a decrease of $2.7 million at the Chipeta complex due to a decrease in average prices.

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Residue purchases decreased by $19.8 million and $49.6 million for the three and six months ended June 30, 2016, respectively, primarily due to decreases of (i) $8.3 million and $26.9 million, respectively, due to the DBM outage, (ii) $5.4 million and $10.4 million, respectively, at the DJ Basin complex due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015, and (iii) $4.2 million and $7.4 million, respectively, at the Hilight system due to decreases in volumes and average prices.

Other items increased by $1.3 million and $0.3 million for the three and six months ended June 30, 2016, respectively, primarily due to fees paid for rerouting volumes due to the DBM outage and changes in imbalance positions primarily at the Chipeta, DBM and DJ Basin complexes.

Operation and maintenance expense decreased by $2.7 million for the three months ended June 30, 2016, primarily due to decreases of (i) $2.6 million in salaries, wages and contract labor primarily attributable to the Granger and DBM complexes and the sale of the Dew and Pinnacle systems in July 2015, (ii) $2.1 million in other operating costs and measurement and well-testing analysis expense primarily attributable to the DJ Basin and DBM complexes and the sale of the Dew and Pinnacle systems in July 2015 and (iii) $1.8 million in chemicals and treating services primarily attributable to the DBM complex and the sale of the Dew and Pinnacle systems in July 2015. These decreases were partially offset by increases of (i) $2.3 million in plant repairs and maintenance primarily at the DBM complex and (ii) $1.6 million in utilities expense primarily at the Chipeta and DJ Basin complexes.

Operation and maintenance expense decreased by $2.6 million for the six months ended June 30, 2016, primarily due to decreases of (i) $7.4 million in other operating costs, water costs, and salaries and wages primarily attributable to the DJ Basin and DBM complexes and the sale of the Dew and Pinnacle systems in July 2015, (ii) $2.6 million in chemicals and treating services primarily attributable to the Hilight system, DBM complex and the sale of the Dew and Pinnacle systems in July 2015 and (iii) $1.4 million in measurement and well-testing analysis expense primarily attributable to the DJ Basin complex and the sale of the Dew and Pinnacle systems in July 2015. These decreases were partially offset by increases of (i) $4.1 million in utilities expense primarily at the Chipeta and DJ Basin complexes, (ii) $2.6 million in plant repairs and maintenance primarily at the Hilight system and the DJ Basin and DBM complexes and (iii) $2.1 million in facilities and overhead expense attributable to the Non-Operated Marcellus Interest systems.

General and Administrative, Depreciation and Amortization, Impairments and Other Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
General and administrative	$10,883	$9,408	16 %	$22,160	$20,489	8 %
Property and other taxes	12,078	9,586	26 %	22,428	18,866	19 %
Depreciation and amortization	67,305	68,554	(2)%	132,400	137,529	(4)%
Impairments	2,403	1,620	48 %	8,921	274,244	(97)%
Total general and administrative, depreciation and amortization, impairments and other expenses	$92,669	$89,168	4 %	$185,909	$451,128	(59)%

General and administrative expenses increased by $1.5 million and $1.7 million for the three and six months ended June 30, 2016, respectively, primarily due to increases in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement and increases in consulting and audit fees.

Property and other taxes increased by $2.5 million and $3.6 million for the three and six months ended June 30, 2016, respectively, primarily due to ad valorem tax increases of $2.7 million and $4.2 million, respectively, at the DJ Basin complex, partially offset by decreases of $0.6 million and $1.2 million, respectively, due to the sale of the Dew and Pinnacle systems in July 2015.

Depreciation and amortization decreased by $1.2 million for the three months ended June 30, 2016, primarily due to depreciation expense decreases of (i) $3.5 million due to the sale of the Dew and Pinnacle systems in July 2015 and (ii) $2.9 million at the Hilight system due to an asset impairment recognized in the fourth quarter of 2015. These decreases were partially offset by an increase of $4.7 million related to ongoing capital projects at the DBM and DJ Basin complexes and the DBJV and Non-Operated Marcellus Interest systems.

Depreciation and amortization decreased by $5.1 million for the six months ended June 30, 2016, primarily due to depreciation expense decreases of (i) $9.3 million at the Red Desert complex and the Hilight system due to asset impairments recognized in the first and fourth quarters of 2015, respectively, and (ii) $7.1 million due to the sale of the Dew and Pinnacle systems in July 2015. These decreases were partially offset by an increase of $10.8 million related to ongoing capital projects at the DBM and DJ Basin complexes and the DBJV, Non-Operated Marcellus Interest and Springfield systems.

Impairment expense increased by $0.8 million for the three months ended June 30, 2016, primarily due to impairments related to the abandonment of compressors at the MIGC system during 2016, as compared to lower impairments in 2015 related to the cancellation of projects at the Red Desert complex.

Impairment expense decreased by $265.3 million for the six months ended June 30, 2016, primarily due to (i) the $264.4 million impairment at the Red Desert complex recognized during the first quarter of 2015 and (ii) impairments related to the abandonment of compressors at the MIGC system and cancellation of projects at the Red Desert complex during 2015. Impairment expense for the six months ended June 30, 2016, included (i) the $6.1 million impairment at the Newcastle system, which was impaired to its estimated fair value of $3.1 million, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment and (ii) impairments related to the abandonment of compressors at the MIGC system.

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Interest Income – Affiliates and Interest Expense

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
Note receivable – Anadarko	$4,225	$4,225	— %	$8,450	$8,450	— %
Interest income – affiliates	$4,225	$4,225	— %	$8,450	$8,450	— %
Third parties						
Long-term debt	$(28,281)	$(24,733)	14 %	$(56,099)	$(48,075)	17 %
Amortization of debt issuance costs and commitment fees	(1,545)	(1,374)	12 %	(3,075)	(2,666)	15 %
Capitalized interest	1,482	2,693	(45)%	3,331	5,787	(42)%
Affiliates						
Deferred purchase price obligation – Anadarko[(1)]	15,461	(4,190)	NM	10,924	(5,610)	NM
Interest expense	$(12,883)	$(27,604)	(53)%	$(44,919)	$(50,564)	(11)%

NM-Not Meaningful

(1) See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q for a discussion of the accretion and net present value of the Deferred purchase price obligation - Anadarko.

Interest expense decreased by $14.7 million and $5.6 million for the three and six months ended June 30, 2016, respectively, primarily due to $15.5 million and $10.9 million, respectively, in accretion revisions recorded as reductions to interest expense for the Deferred purchase price obligation - Anadarko entered into in March 2015 (see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q). The accretion revisions were partially offset by interest incurred on the 2025 Notes issued in June 2015 of $3.5 million and $8.4 million for the three and six months ended June 30, 2016, respectively. Capitalized interest decreased by $1.2 million and $2.5 million for the three and six months ended June 30, 2016, respectively, primarily due to the completion of Lancaster Train II in June 2015 (within the DJ Basin complex). This decrease was partially offset by an increase due to the construction of Trains IV, V and VI at the DBM complex. See Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Income Tax (Benefit) Expense

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2016	2015	Inc/ (Dec)	2016	2015	Inc/ (Dec)
Income (loss) before income taxes	$167,651	$147,405	14 %	$293,367	$6,408	NM
Income tax (benefit) expense	326	12,246	(97)%	6,959	24,516	(72)%
Effective tax rate	— %	8 %		2 %	NM	

NM-Not Meaningful

We are not a taxable entity for U.S. federal income tax purposes. However, our income apportionable to Texas is subject to Texas margin tax. For the periods presented, our variance from the federal statutory rate, which is zero percent as a non-taxable entity, is primarily due to federal and state taxes on pre-acquisition income attributable to Partnership assets acquired from Anadarko, and our share of Texas margin tax.

Income attributable to (i) the Springfield system prior to and including February 2016 and (ii) the DBJV system prior to and including February 2015, was subject to federal and state income tax. Income earned on the Springfield system and the DBJV system for periods subsequent to February 2016 and February 2015, respectively, was only subject to Texas margin tax on income apportionable to Texas.

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KEY PERFORMANCE METRICS

thousands except percentages and per-unit amounts	Three Months Ended June 30, 2016	2015	Inc/ (Dec)	Six Months Ended June 30, 2016	2015	Inc/ (Dec)
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (1)	$294,661	$293,560	— %	$571,190	$564,806	1 %
Adjusted gross margin for crude/NGL assets (2)	34,593	33,237	4 %	69,288	64,641	7 %
Adjusted gross margin attributable to Western Gas Partners, LP (3)	329,254	326,797	1 %	640,478	629,447	2 %
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (4)	0.84	0.73	15 %	0.82	0.72	14 %
Adjusted gross margin per Bbl for crude/NGL assets (5)	2.03	1.98	3 %	2.05	1.95	5 %
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	250,565	245,548	2 %	481,664	465,510	3 %
Distributable cash flow (3)	199,349	211,674	(6)%	391,287	397,252	(2)%

(1) Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets is calculated as total revenues and other for natural gas assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for natural gas assets, plus distributions from our equity investments in Fort Union and Rendezvous, and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. See the reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets to its most comparable GAAP measure below.

(2) Adjusted gross margin for crude/NGL assets is calculated as total revenues and other for crude/NGL assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for crude/NGL assets, plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, and the TEFR Interests. See the reconciliation of Adjusted gross margin for crude/NGL assets to its most comparable GAAP measure below.

(3) For a reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow to the most directly comparable financial measure calculated and presented in accordance with GAAP, see the descriptions below.

(4) Average for period. Calculated as Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets, divided by total throughput (MMcf/d) attributable to Western Gas Partners, LP for natural gas assets.

(5) Average for period. Calculated as Adjusted gross margin for crude/NGL assets, divided by total throughput (MBbls/d) for crude/NGL assets.

Adjusted gross margin attributable to Western Gas Partners, LP. We define Adjusted gross margin attributable to Western Gas Partners, LP ("Adjusted gross margin") as total revenues and other, less cost of product and reimbursements for electricity-related expenses recorded as revenue, plus distributions from equity investees and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. We believe Adjusted gross margin is an important performance measure of the core profitability of our operations, as well as our operating performance as compared to that of other companies in our industry.

Adjusted gross margin increased by $2.5 million and $11.0 million for the three and six months ended June 30, 2016, respectively, primarily due to the start-up of Lancaster Train II in June 2015 (within the DJ Basin complex), partially offset by the DBM outage, the sale of the Dew and Pinnacle systems in July 2015 and lower volumes at the Springfield gas gathering system and the Chipeta and Red Desert complexes. In addition, an increase in volumes at the DBJV system contributed to the overall increase in Adjusted gross margin for the six months ended June 30, 2016.

To facilitate investor and industry analyst comparisons between us and our peers, we also disclose Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets and Adjusted gross margin per Bbl for crude/NGL assets. Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.11 and $0.10 for the three and six months ended June 30, 2016, respectively, primarily due to the start-up of Lancaster Train II in June 2015 (within the DJ Basin complex). Adjusted gross margin per Bbl for crude/NGL assets increased by $0.05 and $0.10 for the three and six months ended June 30, 2016, respectively, due to higher distributions received from FRP and TEP.

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Adjusted EBITDA attributable to Western Gas Partners, LP. We define Adjusted EBITDA attributable to Western Gas Partners, LP ("Adjusted EBITDA") as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation and amortization, impairments, and other expense (including lower of cost or market inventory adjustments recorded in cost of product), less gain (loss) on divestiture and other, net, 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 $5.0 million for the three months ended June 30, 2016, primarily due to a $42.4 million decrease in cost of product, a $2.7 million decrease in operation and maintenance expenses and $2.6 million in proceeds from business interruption insurance claims. These amounts were partially offset by a $37.3 million decrease in total revenues and other, a $2.5 million increase in property and other tax expense, a $1.4 million decrease in distributions from equity investees, and a $1.4 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Adjusted EBITDA increased by $16.2 million for the six months ended June 30, 2016, primarily due to a $105.3 million decrease in cost of product, a $2.6 million decrease in operation and maintenance expenses, $2.6 million in proceeds from business interruption insurance claims and a $1.6 million increase in distributions from equity investees. These amounts were partially offset by a $91.2 million decrease in total revenues and other, a $3.6 million increase in property and other tax expense, and a $1.4 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Distributable cash flow. We define "Distributable cash flow" as Adjusted EBITDA, plus interest income and the net settlement amounts from the sale and/or purchase of natural gas, condensate and NGLs under our commodity price swap agreements to the extent such amounts are not recognized as Adjusted EBITDA, less net cash paid (or to be paid) for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, Series A Preferred unit distributions 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 distributable cash flow 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.

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. Furthermore, to the extent Distributable cash flow includes realized amounts recorded as capital contributions from Anadarko attributable to activity under our commodity price swap agreements, Distributable cash flow is not a reflection of our ability to generate cash from operations.

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Distributable cash flow decreased by $12.3 million for the three months ended June 30, 2016, primarily due to $14.1 million in Series A Preferred unit distributions, a $9.1 million increase in cash paid for maintenance capital expenditures, and a $3.7 million increase in net cash paid for interest expense. These amounts were partially offset by $9.6 million in the above-market component of the swap extensions with Anadarko, where such amount related to the above-market component of swaps did not exist prior to the extensions executed on July 1, 2015, and an increase of $5.0 million in Adjusted EBITDA.

Distributable cash flow decreased by $6.0 million for the six months ended June 30, 2016, primarily due to $16.0 million in Series A Preferred unit distributions, a $13.9 million increase in cash paid for maintenance capital expenditures, and an $8.4 million increase in net cash paid for interest expense. These amounts were partially offset by $16.4 million in the above-market component of the swap extensions with Anadarko, where such amount related to the above-market component of swaps did not exist prior to the extensions executed on July 1, 2015, and an increase of $16.2 million in Adjusted EBITDA.

Reconciliation to GAAP measures. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in GAAP. The GAAP measure used by us that is most directly comparable to Adjusted gross margin is operating income (loss), while net income (loss) attributable to Western Gas Partners, LP and net cash provided by operating activities are the GAAP measures used by us that are most directly comparable to Adjusted EBITDA. The GAAP measure used by us that is most directly comparable to Distributable cash flow is net income (loss) attributable to Western Gas Partners, LP. Our non-GAAP financial measures of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered as alternatives to the GAAP measures of operating income (loss), net income (loss) attributable to Western Gas Partners, LP, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow have important limitations as analytical tools because they exclude some, but not all, items that affect operating income (loss), net income (loss) and net cash provided by operating activities. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Our definitions of Adjusted gross margin, 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 gross margin, Adjusted EBITDA and Distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted gross margin, Adjusted EBITDA and Distributable cash flow compared to (as applicable) operating income (loss), net income (loss) 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 gross margin to the GAAP financial measure of operating income (loss), (b) a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income (loss) attributable to Western Gas Partners, LP and net cash provided by operating activities and (c) a reconciliation of the non-GAAP financial measure of Distributable cash flow to the GAAP financial measure of net income (loss) attributable to Western Gas Partners, LP:

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2016	2015	2016	2015
Reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP to Operating income (loss)				
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$294,661	$293,560	$571,190	$564,806
Adjusted gross margin for crude/NGL assets	34,593	33,237	69,288	64,641
Adjusted gross margin attributable to Western Gas Partners, LP	329,254	326,797	640,478	629,447
Adjusted gross margin attributable to noncontrolling interest	4,183	4,661	8,604	9,469
Gain (loss) on divestiture and other, net	(1,907)	—	(2,539)	(6)
Proceeds from business interruption insurance claims	2,603	—	2,603	—
Equity income, net – affiliates	19,693	18,941	36,507	37,161
Reimbursed electricity-related charges recorded as revenues	14,869	13,221	30,537	25,031
Less:				
Distributions from equity investees	24,491	25,902	49,130	47,572
Operation and maintenance	75,173	77,837	151,386	154,022
General and administrative	10,883	9,408	22,160	20,489
Property and other taxes	12,078	9,586	22,428	18,866
Depreciation and amortization	67,305	68,554	132,400	137,529
Impairments	2,403	1,620	8,921	274,244
Operating income (loss)	$176,362	$170,713	$329,765	$48,380

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thousands	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net income (loss) attributable to Western Gas Partners, LP				
Adjusted EBITDA attributable to Western Gas Partners, LP	$250,565	$245,548	$481,664	$465,510
Less:				
Distributions from equity investees	24,491	25,902	49,130	47,572
Non-cash equity-based compensation expense	1,246	1,163	2,549	2,275
Interest expense	12,883	27,604	44,919	50,564
Income tax expense	326	12,246	6,959	24,516
Depreciation and amortization [(1)]	66,650	67,904	131,089	136,231
Impairments	2,403	1,620	8,921	274,244
Other expense [(1)]	56	—	56	—
Add:				
Gain (loss) on divestiture and other, net	(1,907)	—	(2,539)	(6)
Equity income, net – affiliates	19,693	18,941	36,507	37,161
Interest income – affiliates	4,225	4,225	8,450	8,450
Other income [(1)]	—	68	122	137
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net cash provided by operating activities				
Adjusted EBITDA attributable to Western Gas Partners, LP	$250,565	$245,548	$481,664	$465,510
Adjusted EBITDA attributable to noncontrolling interest	3,456	3,463	7,133	7,335
Interest income (expense), net	(8,658)	(23,379)	(36,469)	(42,114)
Uncontributed cash-based compensation awards	(86)	(68)	(158)	(145)
Accretion and amortization of long-term obligations, net	(14,522)	4,958	(9,055)	7,070
Current income tax benefit (expense)	(198)	(11,673)	(4,979)	(18,134)
Other income (expense), net	(53)	71	71	142
Distributions from equity investments in excess of cumulative earnings – affiliates	(5,827)	(5,574)	(10,611)	(8,538)
Changes in operating working capital:				
Accounts receivable, net	(45,800)	(26,725)	(33,242)	(41,358)
Accounts and imbalance payables and accrued liabilities, net	(20,205)	(8,389)	(2,227)	4,407
Other	(1,309)	(744)	1,739	(1,854)
Net cash provided by operating activities	$157,363	$177,488	$393,866	$372,321
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			$393,866	$372,321
Net cash used in investing activities			(952,824)	(371,878)
Net cash provided by (used in) financing activities			618,692	20,271

(1) Includes our 75% share of depreciation and amortization; other expense; and other income attributable to the Chipeta complex.

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thousands except Coverage ratio	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Reconciliation of Distributable cash flow to Net income (loss) attributable to Western Gas Partners, LP and calculation of the Coverage ratio				
Distributable cash flow	$199,349	$211,674	$391,287	$397,252
Less:				
Distributions from equity investees	24,491	25,902	49,130	47,572
Non-cash equity-based compensation expense	1,246	1,163	2,549	2,275
Interest expense, net (non-cash settled) (1)	(15,461)	4,190	(10,924)	5,610
Income tax (benefit) expense	326	12,246	6,959	24,516
Depreciation and amortization (2)	66,650	67,904	131,089	136,231
Impairments	2,403	1,620	8,921	274,244
Above-market component of swap extensions with Anadarko (3)	9,552	—	16,365	—
Other expense (2)	56	—	56	—
Add:				
Gain (loss) on divestiture and other, net	(1,907)	—	(2,539)	(6)
Equity income, net – affiliates	19,693	18,941	36,507	37,161
Cash paid for maintenance capital expenditures (2)	21,085	11,992	39,982	26,105
Capitalized interest	1,482	2,693	3,331	5,787
Cash paid for (reimbursement of) income taxes	—	—	67	(138)
Series A Preferred unit distributions	14,082	—	15,969	—
Other income (2)	—	68	122	137
Net income (loss) attributable to Western Gas Partners, LP	$164,521	$132,343	$280,581	$(24,150)
Distributions declared (4)				
Limited partners – common units	$108,458		$214,951	
General partner	54,369		106,781	
Total	$162,827		$321,732	
Coverage ratio	1.22 x		1.22 x	

(1) Includes accretion revisions related to the Deferred purchase price obligation - Anadarko. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

(2) Includes our 75% share of depreciation and amortization; other expense; cash paid for maintenance capital expenditures; and other income attributable to the Chipeta complex.

(3) See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

(4) Reflects cash distributions of $0.830 and $1.645 per unit declared for the three and six months ended June 30, 2016, respectively.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and capital expenditures, debt service, customary operating expenses, quarterly distributions to our limited partners and general partner, and distributions to our noncontrolling interest owner. Our sources of liquidity as of June 30, 2016, included cash and cash equivalents, cash flows generated from operations, 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. 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, including the extension of commodity price swap agreements, 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.

We have filed an insurance claim for the incident at the DBM complex and are currently in the adjusting process with insurers. Recoveries from the business interruption claim related to the DBM outage are recognized as income when non-refundable cash proceeds are received from insurers. As of June 30, 2016, we had received $5.5 million in cash proceeds from insurers related to the incident at the DBM complex, including $2.6 million in proceeds from business interruption insurance claims and $2.9 million in proceeds from property insurance claims (see Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q). Through the date of this filing, we had received an additional $29.1 million in cash proceeds to be recorded in the third quarter of 2016, consisting of $13.7 million in proceeds from business interruption insurance claims and $15.4 million in proceeds from property insurance claims.

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 IPO and have increased our quarterly distribution each quarter since the second quarter of 2009. On July 20, 2016, the Board of Directors of our general partner declared a cash distribution to our unitholders of $0.830 per unit, or $162.8 million in aggregate, including incentive distributions, but excluding distributions on Class C units and Series A Preferred units. The cash distribution is payable on August 12, 2016, to unitholders of record at the close of business on August 1, 2016. In connection with the closing of the DBM acquisition in November 2014, we issued Class C units that will receive distributions in the form of additional Class C units until the end of 2017, unless earlier converted (see Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q). The Class C unit distribution, if paid in cash, would have been $9.9 million for the second quarter of 2016. In connection with the closing of the Springfield acquisition in March 2016, we issued the March 2016 Series A units, and in April 2016, we issued the April 2016 Series A units pursuant to the full exercise of the option granted in connection with the March 2016 Series A units issuance. These Series A Preferred units will receive quarterly distributions in cash equal to $0.68 per Series A Preferred unit, subject to certain adjustments. See Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. For the quarter ended June 30, 2016, the Series A Preferred unitholders will receive an aggregate cash distribution of $14.1 million comprised of (i) a per unit distribution prorated for the 77-day period the April 2016 Series A units were outstanding during the second quarter of 2016 and (ii) a full quarterly per unit distribution on the March 2016 Series A units. For the quarter ended March 31, 2016, the holders of the March 2016 Series A units received an aggregate cash distribution of $1.9 million, based on the per unit distribution prorated for the 18-day period the March 2016 Series A units were outstanding during the first quarter of 2016.

Management continuously monitors our leverage position and coordinates our capital expenditure program, quarterly distributions and acquisition strategy with our 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. Read Risk Factors under Part II, Item 1A of this Form 10-Q.

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Working capital. As of June 30, 2016, we had $143.7 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital includes the estimated property insurance receivable related to the DBM outage. See Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. 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. As of June 30, 2016, we had $655.1 million available for borrowing under our RCF. See Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, 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 (for fiscal year 2016, the general partner's Board of Directors has approved Estimated Maintenance Capital Expenditures (as defined in our partnership agreement) of $17.7 million per quarter); or

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

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

	Six Months Ended June 30,	
thousands	2016	2015
Acquisitions	$715,199	$12,570
Expansion capital expenditures	$212,081	$335,486
Maintenance capital expenditures	39,988	26,312
Total capital expenditures (1) (2)	$252,069	$361,798
Capital incurred (2) (3)	$261,342	$309,621

(1) Maintenance capital expenditures for the six months ended June 30, 2016 and 2015, are presented net of $3.9 million and zero, respectively, of contributions in aid of construction costs from affiliates. Capital expenditures for the six months ended June 30, 2015, included $23.6 million of pre-acquisition capital expenditures for the Springfield system.

(2) Includes the noncontrolling interest owner's share of Chipeta's capital expenditures for all periods presented. For the six months ended June 30, 2016 and 2015, included $3.3 million and $5.8 million, respectively, of capitalized interest.

(3) Capital incurred for the six months ended June 30, 2015, included $22.2 million of pre-acquisition capital incurred for the Springfield system.

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Acquisitions during 2016 included Springfield and equipment purchases from Anadarko. Acquisitions during 2015 included equipment purchases from Anadarko and the post-closing purchase price adjustments related to the DBM acquisition. See Note 2—Acquisitions and Divestitures and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.
Capital expenditures, excluding acquisitions, decreased by $109.7 million for the six months ended June 30, 2016. Expansion capital expenditures decreased by $123.4 million (including a $2.5 million decrease in capitalized interest) for the six months ended June 30, 2016, primarily due to a decrease of $153.0 million at the DJ Basin complex as a result of decreased activity in 2016. In addition, there were decreases of $22.5 million at the Non-Operated Marcellus Interest systems, $19.1 million at the Springfield system, $14.6 million at the Hilight system, and $7.0 million at the Anadarko-Operated Marcellus Interest systems. These decreases were partially offset by an increase of $92.7 million due to continued construction at the DBM complex and an increase of $13.6 million at the DBJV system.
Maintenance capital expenditures increased by $13.7 million, primarily due to an increase at the DBM complex, partially offset by decreased expenditures at the DJ Basin complex and the Springfield system.
We have updated our estimated total capital expenditures for the year ending December 31, 2016, (including our 75% share of Chipeta's capital expenditures and equity investments, but excluding acquisitions) from an originally reported $450 million to $490 million, to a current range of $490 million to $530 million.

Historical cash flow. The following table and discussion present a summary of our net cash flows provided by (used in) operating activities, investing activities and financing activities:

	Six Months Ended June 30,	
thousands	2016	2015
Net cash provided by (used in):		
Operating activities	$393,866	$372,321
Investing activities	(952,824)	(371,878)
Financing activities	618,692	20,271
Net increase in cash and cash equivalents	$59,734	$20,714

Operating Activities. Net cash provided by operating activities during the six months ended June 30, 2016 and 2015, increased primarily due to the impact of changes in working capital items. Refer to Operating Results within this Item 2 for a discussion of our results of operations as compared to the prior periods.

Investing Activities. Net cash used in investing activities for the six months ended June 30, 2016, included the following:

- $712.5 million of cash paid for the acquisition of Springfield;
- $252.1 million of capital expenditures, net of $3.9 million of contributions in aid of construction costs from affiliates, primarily related to plant construction and expansion at the DBM and DJ Basin complexes and the DBJV system;
- $2.7 million of cash paid for equipment purchases from Anadarko;
- $10.6 million of distributions from equity investments in excess of cumulative earnings; and
- $2.9 million of proceeds from property insurance claims attributable to the DBM outage.

Net cash used in investing activities for the six months ended June 30, 2015, included the following:

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$361.8 million of capital expenditures primarily related to the construction of Train IV at the DBM complex, continued construction of Lancaster Train II (within the DJ Basin complex) and expansion at the DBJV system;

- $9.1 million of cash paid for equipment purchases from Anadarko;

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- $6.8 million of cash contributed to equity investments, primarily related to the expansion projects at White Cliffs, TEP and FRP;

- $3.5 million of cash paid for post-closing purchase price adjustments related to the DBM acquisition; and

- $8.5 million of distributions from equity investments in excess of cumulative earnings.

Financing Activities. Net cash provided by financing activities for the six months ended June 30, 2016, included the following:

- $440.0 million of net proceeds from the March 2016 Series A units issuance, all of which was used to fund a portion of the acquisition of Springfield;

- $530.0 million of borrowings under our RCF, which were used to fund a portion of the Springfield acquisition and for general partnership purposes, including funding capital expenditures;

- $246.9 million of net proceeds from the April 2016 Series A units issuance, all of which was used to pay down amounts borrowed under our RCF in connection with the Springfield acquisition;

- $25.0 million of net proceeds from the sale of common units to WGP, all of which was used to fund a portion of the acquisition of Springfield;

- $16.4 million of capital contribution from Anadarko related to the above-market component of swap extensions (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q);

- $313.4 million of distributions paid to our unitholders;

- $27.5 million of net contributions from Anadarko representing pre-acquisition intercompany transactions attributable to Springfield; and

- $7.5 million of distributions paid to the noncontrolling interest owner of Chipeta.

Net cash provided by financing activities for the six months ended June 30, 2015, included the following:

- $489.7 million of net proceeds from the 2025 Notes offering in June 2015, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under our RCF;

- $280.0 million of borrowings under our RCF, which were used for general partnership purposes, including funding capital expenditures;

- $57.4 million of net proceeds from sales of common units under the $500.0 million COP (as discussed in Securities within this Item 2). Net proceeds were used for general partnership purposes, including funding capital expenditures;

- $17.4 million of net contributions from Anadarko representing pre-acquisition intercompany transactions attributable to Springfield and DBJV;

- $259.2 million of distributions paid to our unitholders; and

- $7.2 million of distributions paid to the noncontrolling interest owner of Chipeta.

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Debt and credit facility. At June 30, 2016, our debt consisted of $500.0 million aggregate principal amount of the 2021 Notes, $670.0 million aggregate principal amount of the 2022 Notes, $350.0 million aggregate principal amount of the 2018 Notes, $400.0 million aggregate principal amount of the 2044 Notes, $500.0 million aggregate principal amount of the 2025 Notes, and $540.0 million of borrowings outstanding under our RCF. As of June 30, 2016, the carrying value of our outstanding debt was $2.9 billion. See Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Senior Notes. At June 30, 2016, we were in compliance with all covenants under the indentures governing our outstanding notes.
In July 2016, we issued the 2026 Notes which were offered at a price to the public of 99.796% of the face amount. Interest is paid semi-annually on January 1 and July 1 of each year. Proceeds (net of underwriting discount of $3.1 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the RCF.

Revolving credit facility. As of June 30, 2016, we had $540.0 million of outstanding borrowings, $4.9 million in outstanding letters of credit and $655.1 million available for borrowing under the RCF, which matures in February 2019. At June 30, 2016, the interest rate on the RCF was 1.77%, the facility fee rate was 0.20% and we were in compliance with all covenants under the RCF.
In April 2016, we repaid $250.0 million of outstanding borrowings under our RCF, $246.9 million of which was funded with the proceeds from the issuance of the April 2016 Series A units. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. Additionally, in July 2016, we repaid $540.0 million of outstanding borrowings under our RCF, primarily with the proceeds from the issuance of the 2026 Notes.

Interest rate agreements. In June 2016, we entered into a U.S. Treasury rate lock agreement to mitigate the risk of rising interest rates on existing variable-rate debt expected to be refinanced during the third quarter of 2016. The rate lock agreement was not designated as a cash flow hedge and was settled in June 2016 upon the offering of the 2026 Notes that closed in July 2016. We realized a loss of $0.2 million at settlement, which is included in Other income (expense), net in the consolidated statements of operations.

Deferred purchase price obligation - Anadarko. The consideration to be paid for the acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. The cash payment will be equal to (a) eight multiplied by the average of our share in the Net Earnings (see definition below) of DBJV for the calendar years 2018 and 2019, less (b) our share of all capital expenditures incurred for DBJV between March 1, 2015, and February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. As of the acquisition date, the estimated future payment obligation (based on management's estimate of our share of forecasted Net Earnings and capital expenditures for DBJV) was $282.8 million, which had a net present value of $174.3 million, using a discount rate of 10%. As of June 30, 2016, we recognized a $241.1 million decrease in the estimated future payment obligation, resulting in a net present value of this obligation of $29.2 million calculated using a discounted cash flow model with a 10% discount rate. The reduction in the value of the deferred purchase price obligation is primarily due to revisions reflecting a decrease in our estimate of 2018 and 2019 Net Earnings and an increase in our estimate of aggregate capital expenditures to be incurred by DBJV through February 29, 2020. The accretion revision, which was recorded as a reduction to Interest expense, was $15.5 million and $10.9 million for the three and six months ended June 30, 2016, respectively. Accretion expense was $4.2 million and $5.6 million for the three and six months ended June 30, 2015, respectively. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statements on file with the SEC. We may issue common units under the $500.0 million COP, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of June 30, 2016, we had the capacity to issue additional common units with an aggregate sales price of up to $441.8 million under the $500.0 million COP. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q for a discussion of trades completed under the $500.0 million COP.

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In March 2016, in connection with the issuance of the March 2016 Series A units, we entered into a Registration Rights Agreement with the Series A Preferred unit purchasers, pursuant to which we agreed to use our commercially reasonable efforts to file and maintain a registration statement with respect to the resale of common units that are issuable upon conversion of the Series A Preferred units. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q for a discussion of the Series A Preferred units.

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 a majority of our volumes (excluding our equity investment throughput), 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. 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 a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, and are subject to performance risk thereunder. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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 9—Debt and Interest Expense and Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q for an update to our contractual obligations as of June 30, 2016, including, but not limited to, increases in committed capital.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases and standby letters of credit. The information pertaining to operating leases and our standby letters of credit required for this item is provided under Note 10—Commitments and Contingencies and Note 9—Debt and Interest Expense, respectively, included in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

RECENT ACCOUNTING DEVELOPMENTS

See Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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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, condensate and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of residue and/or NGLs. Under keep-whole agreements, we keep 100% of the NGLs produced, and the processed natural gas, or value of the natural gas, is returned to the producer. Since some of the gas is used and removed during processing, we compensate the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas used.

To mitigate our exposure to a majority of the 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 in December 2016. On June 25, 2015, we extended our commodity price swap agreements with Anadarko for the DJ Basin complex from July 1, 2015, through December 31, 2015, and for the Hugoton system from October 1, 2015, through December 31, 2015. On December 8, 2015, the DJ Basin complex and Hugoton system swaps were further extended from January 1, 2016, through December 31, 2016. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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 (loss) that is impacted by changes in market prices. Accordingly, we do not expect a 10% increase or decrease in natural gas or NGL prices would have a material impact on our operating income (loss), financial condition or cash flows for the next twelve months, excluding the effect of natural gas imbalances described below.

We 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 the six months ended June 30, 2016, were low compared to historic rates. In December 2015, while raising the target range for the federal funds rate from zero to between 1/4 to 1/2 percent, the Federal Open Market Committee signaled that further increases are likely over the medium term. Any such increases in the federal funds rate will ultimately result in an increase in our financing costs. As of June 30, 2016, we had $540.0 million of outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). If interest rates rise, our future financing costs could increase. A 10% change in LIBOR would have resulted in a nominal change in net income (loss) and the fair value of the borrowings under the RCF at June 30, 2016.

We may incur additional variable-rate 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 (for purposes of this Item 4, “Management”) performed an evaluation of the Partnership’s disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the 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 or submit 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, Management has concluded that the Partnership’s disclosure controls and procedures are effective as of June 30, 2016.

Remediation Plan. As disclosed in Management’s Assessment of Internal Control over Financial Reporting under Part II, Item 8 of the Partnership’s Form 10-K for the year ended December 31, 2015, which was filed with the SEC on February 25, 2016, as of December 31, 2015, Management determined that a material weakness (as defined in the regulations of the SEC) existed in the Partnership’s internal control over financial reporting. Beginning in the first quarter of 2016, the Partnership, subject to senior management review, began remediating this material weakness by, among other things, implementing a training program for the personnel involved in the impairment determination processes and controls to ensure business understanding and the proper application of GAAP and the Partnership’s accounting policies related to the impairment of long-lived assets. During the second quarter of 2016, the Partnership completed these remediation activities by testing the operating effectiveness of the aforementioned efforts and found them to be effective. As a result, Management has concluded that the material weakness had been remediated as of June 30, 2016. As the Partnership continues to evaluate and work to improve its internal control over financial reporting, Management may execute additional measures to address the material weakness or modify the remediation plan described above and will continue to review and make necessary changes to the overall design of the Partnership’s internal controls.

Changes in Internal Control Over Financial Reporting. Except as noted under the caption Remediation Plan within this Item 4, there has been no change in our internal control over financial reporting during the quarter ended June 30, 2016, that has materially affected, or is reasonably likely to materially affect, the Partnership’s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

WGR Operating, LP, one of our subsidiaries, is currently in negotiations with the U.S. Environmental Protection Agency with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act at its Granger, Wyoming facility. Although management cannot predict the outcome of settlement discussions, management believes that it is reasonably likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Except as discussed above, 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 a 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 included below, as well as those set forth under Part I, Item 1A in our Form 10-K for the year ended December 31, 2015, together with all of the other information included in this document, 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, 2015, 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.

New pipeline safety legislation could result in more stringent requirements on our gas pipelines and gathering lines, which could trigger significant capital costs and costs of operation.

On June 22, 2016, President Obama signed new pipeline safety legislation, the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the "PIPES Act"), just recently passed by Congress. Extending the federal Pipeline and Hazardous Materials Safety Administration's ("PHMSA") statutory mandate through 2019, the PIPES Act establishes or continues the development of requirements affecting pipeline safety including, but not limited to, the following: (i) providing PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing; (ii) obligating PHMSA to develop safety standards for natural gas storage facilities by June 22, 2018; and (iii) requiring PHMSA to complete certain of the outstanding mandates under existing legislation and to report to Congress on the status of overdue rulemakings. The development and/or implementation of more stringent requirements pursuant to the PIPES Act could cause us to incur increased capital costs and costs of operation as necessary to comply with such standards, which costs could be significant.

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The holders of our Series A Preferred units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units, and could dilute or otherwise adversely affect the holders of our common units.

The holders of our Series A Preferred units, first issued in March 2016, are entitled to certain rights that are senior to the rights of holders of common and Class C units, such as rights to distributions and rights upon liquidation of the Partnership. No payment or distribution on any junior equity security of the Partnership, including common and Class C units, for any quarter is permitted prior to the payment in full of the Series A Preferred unit distribution (including any outstanding arrearages). These preferences could adversely affect the market price for our common units, or could make it more difficult for us to issue and sell common units in the future.

In addition, distributions on the Series A Preferred units accrue and are cumulative, at a quarterly rate of $0.68 per unit, and the Series A Preferred units are convertible into common units by the holders or by us in certain circumstances. Our obligation to pay distributions on the Series A Preferred units, or on the common units issued following the conversion of the Series A Preferred units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general partnership purposes. Our obligations to the holders of Series A Preferred units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

In addition, the holders of our Series A Preferred units may convert the Series A Preferred units into common units on a one-for-one basis at any time after the second anniversary of the issuance date, in whole or in part, subject to certain conversion thresholds. Similarly, the Partnership may convert the Series A Preferred units at any time after the third anniversary of the issuance date, in whole or in part, subject to certain conversion thresholds. If a substantial portion of the Series A Preferred units are converted into common units, common unitholders could experience significant dilution. Further, if holders of converted Series A Preferred units dispose of a substantial portion of such common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. These sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Proposed rule changes regarding gas pipeline safety could impose more stringent standards on our gas pipelines and gathering lines that, if adopted, may result in increased significant capital costs and costs of operation.

On March 17, 2016, the federal Pipeline and Hazardous Materials Safety Administration (“PHMSA”) announced a proposed rulemaking that would, if adopted, impose more stringent requirements for certain gas lines and gathering lines under varying circumstances. Among other things, the proposed rulemaking would extend certain of PHMSA’s current regulatory safety programs for gas pipelines beyond “high consequence areas” to newly defined “moderate consequence areas” that contain as few as 5 dwellings within the potential impact area; require gas pipelines installed before 1970 and thus “grandfathered,” or excluded, from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures (“MAOP”); and require gathering lines in Class I areas, both onshore and offshore, to comply with standards regarding damage prevention, corrosion control (for metallic pipe), public education, MAOP limits, line markers and emergency planning if such gathering lines’ nominal design is 8 inches or more. In order to provide clarity and greater certainty on what may constitute a “gathering line,” PHMSA is proposing a new definition of that term under the rulemaking, which term would now encompass “a pipeline, or a connected series of pipelines, and equipment used to collect gas from the endpoint of a production facility/operation and transport it to the furthermost point downstream of the following endpoints” including the “inlet of 1st gas processing plant;” the “outlet of” a gas treatment facility (not associated with a processing plant or compressor station); the “[o]utlet of the furthermost downstream compressor” leading to a pipeline; or the “point where separate production fields are commingled.” Other new requirements proposed by PHMSA under the rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. Adoption of some or all of these standards under the proposed rulemaking could cause us to incur increased capital costs and costs of operation, which costs could be significant.

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Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer all, but not less than all, of its general partner interest to a third party in connection with a merger or consolidation or the transfer of all or substantially all of its assets without the consent of our unitholders. On or after June 30, 2018, such transfer may be effected in whole or in part without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of (i) WGP to transfer all or a portion of its ownership interest in our general partner to a third party, or (ii) Anadarko to transfer all or a portion of its ownership interest in WGP and/or WGP's general partner to a third party. Additionally, in March 2016, WGP entered into a secured credit facility under which it has pledged, among other things, its entire interest in our general partner. If WGP were to default, the lenders party to this facility could foreclose upon the interest and take control of our general partner. Any new owner of our general partner or WGP's general partner, as the case may be, would then be in a position to replace the Board of Directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the Board of Directors and officers.

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

During the three and six months ended June 30, 2016, in connection with the quarterly distribution for the Class C units, we issued the following PIK Class C units to APC Midstream Holdings, LLC, a subsidiary of Anadarko and the holder of the Class C units:

thousands except unit amounts Quarters Ended	PIK Class C Units	Implied Fair Value	Date of Distribution
2015			
December 31	323,584	$10,070	February 2016
2016			
March 31	210,562	$10,356	May 2016

No proceeds were received as consideration for the issuance of the PIK Class C units. The PIK Class C units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended. All outstanding Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. For more information, see Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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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.

Exhibit Number	Description
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).
2.8#	Contribution Agreement, dated as of February 27, 2013, by and among Anadarko Marcellus Midstream, L.L.C., Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, Anadarko Petroleum Corporation and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
2.9#	Contribution Agreement, dated as of February 27, 2014, by and among WGR Asset Holding Company LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.9 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 28, 2014, File No. 001-34046).
2.10#	Agreement and Plan of Merger, dated October 28, 2014, by and among Western Gas Partners, LP, Maguire Midstream LLC and Nuevo Midstream, LLC (incorporated by reference to Exhibit 2.1 to Western Gas

	Partners, LP's Current Report on Form 8-K filed on October 28, 2014, File No. 001-34046).
2.11#	Purchase and Sale Agreement, dated as of March 2, 2015, by and among WGR Asset Holding Company LLC, Delaware Basin Midstream, LLC, Western Gas Partners, LP, and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 3, 2015, File No. 001-34046).
2.12#	Contribution Agreement, dated as of February 24, 2016, by and among WGR Asset Holding Company, LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 1, 2016, File No.001-34046).

Exhibit Number	Description
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	Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 14, 2016 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).
3.3	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 14, 2016 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).
3.4	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).
3.5	Second Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated December 12, 2012 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, 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 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.7	Fifth Supplemental Indenture, dated as of August 14, 2013, 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 August 14, 2013, File No. 001-34046).
4.8	Form of 2.600% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.9	Sixth Supplemental Indenture, dated as of March 20, 2014, among Western Gas Partners, LP, as Issuer, 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 March 20, 2014, File No. 001-34046).
4.10	Form of 5.450% Senior Notes due 2044 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.11	Seventh Supplemental Indenture, dated as of June 4, 2015, 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 4, 2015, File No. 001-34046).
4.12	Form of 3.950% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 4, 2015, File No. 001-34046).

4.13	Registration Rights Agreement by and between Western Gas Partners, LP and the Purchasers party thereto, dated as of March 14, 2016, (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 16, 2016, File No. 001-34046).

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Exhibit Number	Description
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

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.

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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

July 27, 2016

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

July 27, 2016

/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)