Western Gas Partners LP
Form 10-Q
November 01, 2017
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q
(Mark One)

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

For the quarterly period ended September 30, 2017

Or

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

For the transition period from to

Commission file number: 001-34046

WESTERN GAS PARTNERS, LP
(Exact name of registrant as specified in its charter)

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

(832) 636-6000
(Registrant's telephone number, including area code)

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

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

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

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨	Emerging growth company ¨

(Do not check if a smaller
reporting company)

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

There were 152,602,105 common units outstanding as of October 30, 2017.

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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 and definitions below have the following meanings:
Additional DBJV System Interest: The Partnership’s additional 50% interest in the DBJV system acquired from a third party in March 2017.
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.
Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Bbls/d: Barrels per day.
Board of Directors or Board: The board of directors of our general partner.
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 in West Texas.
DBM: Delaware Basin Midstream, LLC.
DBM complex: The cryogenic processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.
DBM water systems: Two produced-water disposal systems in West Texas.
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.

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Fractionation: The process of applying various levels of higher pressure and lower temperature to separate a stream of natural gas liquids into ethane, propane, normal butane, isobutane and natural gasoline for end-use sale.
FRP: Front Range Pipeline LLC.
GAAP: Generally accepted accounting principles in the United States.
General partner: Western Gas Holdings, LLC.
Hydraulic fracturing: The injection of fluids into the wellbore to create fractures in rock formations, stimulating the production of oil or gas.
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.
Marcellus Interest: Our 33.75% interest in the Larry’s Creek, Seely and Warrensville gas gathering systems and related facilities located in northern Pennsylvania. Formerly defined as the “Anadarko-Operated Marcellus Interest”.
MBbls/d: One thousand barrels per day.
MGR: Mountain Gas Resources, LLC.
MGR assets: The Red Desert complex and the Granger straddle plant.
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: The 33.75% interest in the Liberty and Rome gas gathering systems and related facilities located in northern Pennsylvania that was transferred to a third party in March 2017 pursuant to the Property Exchange.
Produced water: Byproduct associated with the production of crude oil and natural gas that often contains a number of dissolved solids and other materials found in oil and gas reservoirs.
Property Exchange: The Partnership’s acquisition of the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration, as further described in our Forms 8-K filed with the SEC on February 9, 2017, and March 23, 2017.
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.

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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: The Springfield gas gathering system and Springfield oil gathering system.
TEFR Interests: The interests in TEP, TEG and FRP.
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.
2026 Notes: Our 4.650% Senior Notes due 2026.
2044 Notes: Our 5.450% Senior Notes due 2044.
$500.0 million COP: The COP contemplated by the registration statement filed with the SEC in July 2017 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 September 30,		Nine Months Ended September 30,	
thousands except per-unit amounts	2017	2016	2017	2016
Revenues and other – affiliates				
Gathering, processing and transportation	$157,303	$189,465	$484,601	$563,916
Natural gas and natural gas liquids sales	185,002	135,847	489,172	336,385
Other	8,822	—	8,822	—
Total revenues and other – affiliates	351,127	325,312	982,595	900,301
Revenues and other – third parties				
Gathering, processing and transportation	148,884	125,727	428,835	346,416
Natural gas and natural gas liquids sales	74,139	28,189	201,318	43,200
Other	545	2,417	3,590	3,533
Total revenues and other – third parties	223,568	156,333	633,743	393,149
Total revenues and other	574,695	481,645	1,616,338	1,293,450
Equity income, net – affiliates	21,519	20,294	62,708	56,801
Operating expenses				
Cost of product (1)	239,223	145,643	631,859	326,959
Operation and maintenance (1)	79,536	74,755	229,444	226,141
General and administrative (1)	12,158	11,382	35,402	33,542
Property and other taxes	11,215	10,670	35,433	33,098
Depreciation and amortization	72,539	67,246	216,272	199,646
Impairments	2,159	2,392	170,079	11,313
Total operating expenses	416,830	312,088	1,318,489	830,699
Gain (loss) on divestiture and other, net	72	(6,230)	135,017	(8,769)
Proceeds from business interruption insurance claims	—	13,667	29,882	16,270
Operating income (loss)	179,456	197,288	525,456	527,053
Interest income – affiliates	4,225	4,225	12,675	12,675
Interest expense (2)	(35,544)	(30,768)	(106,794)	(75,687)
Other income (expense), net	286	153	969	224
Income (loss) before income taxes	148,423	170,898	432,306	464,265
Income tax (benefit) expense	510	472	4,905	7,431
Net income (loss)	147,913	170,426	427,401	456,834
Net income attributable to noncontrolling interest	4,407	2,680	8,555	8,507
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Limited partners' interest in net income (loss):				
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Pre-acquisition net (income) loss allocated to Anadarko	—	—	—	(11,326)
Series A Preferred units interest in net (income) loss	—	(25,539)	(42,373)	(50,989)
General partner interest in net (income) loss (3)	(78,376)	(60,551)	(222,903)	(174,332)
Common and Class C limited partners' interest in net income (loss) (3)	65,130	81,656	153,570	211,680
Net income (loss) per common unit – basic and diluted (4)	$0.38	$0.54	$0.91	$1.39

(1) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $22.9 million and $60.5 million for the three and nine months ended September 30, 2017, respectively, and $21.3 million and $68.0 million for the three and nine months ended September 30, 2016, respectively. Operation and maintenance includes charges from Anadarko of $18.1 million and $53.7 million for the three and nine months ended September 30, 2017, respectively, and $15.1 million and $50.7 million for the three and nine months ended September 30, 2016, respectively. General and administrative includes charges from Anadarko of $10.1 million and $29.0 million for the three and nine months ended September 30, 2017, respectively, and $9.5 million and $27.6 million for the three and nine months ended September 30, 2016, respectively. See Note 5.

(2) Includes affiliate (as defined in Note 1) amounts of zero and $(0.1) million for the three and nine months ended September 30, 2017, respectively, and $1.2 million and $12.1 million for the three and nine months ended September 30, 2016, respectively. See Note 2 and Note 9.

(3) 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.

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

See accompanying Notes to Consolidated Financial Statements.

WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	September 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$152,435	$357,925
Accounts receivable, net [1]	192,530	223,223
Other current assets	13,381	12,866
Total current assets	358,346	594,014
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	7,582,178	6,861,942
Less accumulated depreciation	2,074,464	1,812,010
Net property, plant and equipment	5,507,714	5,049,932
Goodwill	417,610	417,610
Other intangible assets	782,376	803,698
Equity investments	573,622	594,208
Other assets	14,643	13,566
Total assets	$7,914,311	$7,733,028
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables [2]	$302,848	$247,076
Accrued ad valorem taxes	33,020	23,121
Accrued liabilities [3]	57,496	45,108
Total current liabilities	393,364	315,305
Long-term debt	3,343,886	3,091,461
Deferred income taxes	10,284	6,402
Asset retirement obligations and other	146,248	142,641
Deferred purchase price obligation – Anadarko [4]	—	41,440
Total long-term liabilities	3,500,418	3,281,944
Total liabilities	3,893,782	3,597,249
Equity and partners' capital		
Series A Preferred units (zero and 21,922,831 units issued and outstanding at September 30, 2017, and December 31, 2016, respectively) [5]	—	639,545
Common units (152,602,105 and 130,671,970 units issued and outstanding at September 30, 2017, and December 31, 2016, respectively)	3,012,424	2,536,872
Class C units (12,977,633 and 12,358,123 units issued and outstanding at September 30, 2017, and December 31, 2016, respectively) [6]	771,856	750,831
General partner units (2,583,068 units issued and outstanding at September 30, 2017, and December 31, 2016)	172,180	143,968
Total partners' capital	3,956,460	4,071,216
Noncontrolling interest	64,069	64,563
Total equity and partners' capital	4,020,529	4,135,779
Total liabilities, equity and partners' capital	$7,914,311	$7,733,028

(1)

Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $78.4 million and $76.6 million as of September 30, 2017, and December 31, 2016, respectively. Accounts receivable, net as of December 31, 2016, also includes an insurance claim receivable related to an incident at the DBM complex. See Note 1.

(2) Accounts and imbalance payables includes affiliate amounts of $0.2 million and zero as of September 30, 2017, and December 31, 2016, respectively.

(3) Accrued liabilities includes affiliate amounts of $0.3 million and zero as of September 30, 2017, and December 31, 2016, respectively.

(4) See Note 2.

(5) The Series A Preferred units converted into common units on a one-for-one basis in 2017. See Note 4.

(6) The Class C units will convert into common units on a one-for-one basis on March 1, 2020, 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, 2016	$—	$2,536,872	$750,831	$639,545	$143,968	$ 64,563	$4,135,779
Net income (loss)	—	171,075	17,415	7,453	222,903	8,555	427,401
Above-market component of swap agreements with Anadarko [(1)]	—	46,719	—	—	—	—	46,719
Conversion of Series A Preferred units into common units [(2)]	—	686,936	—	(686,936)	—	—	—
Amortization of beneficial conversion feature of Class C units and Series A Preferred units	—	(65,909)	3,610	62,299	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(9,049)	(9,049)
Distributions to unitholders	—	(372,123)	—	(22,361)	(194,778)	—	(589,262)
Acquisitions from affiliates	(30)	30	—	—	—	—	—
Revision to Deferred purchase price obligation – Anadarko [(3)]	—	4,165	—	—	—	—	4,165
Contributions of equity-based compensation from Anadarko	—	3,249	—	—	66	—	3,315
Net pre-acquisition contributions from (distributions to) Anadarko	30	—	—	—	—	—	30
Net contributions from (distributions to) Anadarko of other assets	—	1,352	—	—	21	—	1,373
Other	—	58	—	—	—	—	58
Balance at September 30, 2017	$—	$3,012,424	$771,856	$—	$172,180	$ 64,069	$4,020,529

(1) See Note 5.
(2) See Note 4.
(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)

	Nine Months Ended September 30,	
thousands	2017	2016
Cash flows from operating activities		
Net income (loss)	$427,401	$456,834
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	216,272	199,646
Impairments	170,079	11,313
Non-cash equity-based compensation expense	3,573	3,570
Deferred income taxes	3,882	2,321
Accretion and amortization of long-term obligations, net	3,194	(9,176)
Equity income, net – affiliates	(62,708)	(56,801)
Distributions from equity investment earnings – affiliates	64,313	59,671
(Gain) loss on divestiture and other, net	(135,017)	8,769
Lower of cost or market inventory adjustments	140	41
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	(46,972)	(41,108)
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	4,007	24,103
Change in other items, net	(3,065)	(1,445)
Net cash provided by operating activities	645,099	657,738
Cash flows from investing activities		
Capital expenditures	(419,193)	(372,725)
Contributions in aid of construction costs from affiliates	1,386	4,927
Acquisitions from affiliates	(3,910)	(716,465)
Acquisitions from third parties	(155,298)	—
Investments in equity affiliates	(384)	139
Distributions from equity investments in excess of cumulative earnings – affiliates	16,255	16,592
Proceeds from the sale of assets to affiliates	—	623
Proceeds from the sale of assets to third parties	23,370	7,819
Proceeds from property insurance claims	22,977	18,398
Net cash used in investing activities	(514,797)	(1,040,692)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	249,989	1,094,600
Repayments of debt	—	(880,000)
Settlement of the Deferred purchase price obligation – Anadarko [1]	(37,346)	—
Increase (decrease) in outstanding checks	3,310	(1,070)
Proceeds from the issuance of common units, net of offering expenses	(183)	25,000
Proceeds from the issuance of Series A Preferred units, net of offering expenses	—	686,937
Distributions to unitholders [2]	(589,262)	(490,289)
Distributions to noncontrolling interest owner	(9,049)	(11,257)
Net contributions from (distributions to) Anadarko	30	(29,335)
Above-market component of swap agreements with Anadarko [2]	46,719	34,782
Net cash provided by (used in) financing activities	(335,792)	429,368
Net increase (decrease) in cash and cash equivalents	(205,490)	46,414
Cash and cash equivalents at beginning of period	357,925	98,033
Cash and cash equivalents at end of period	$152,435	$144,447

Supplemental disclosures		
Accretion expense and revisions to the Deferred purchase price obligation – Anadarko [1]	$(4,094)	$(172,249)
Net distributions to (contributions from) Anadarko of other assets	(1,373)	581
Interest paid, net of capitalized interest	97,811	82,529
Taxes paid	189	67
Accrued capital expenditures	165,732	49,328
Fair value of properties and equipment from non-cash third party transactions [1]	551,453	—

(1) See 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. WGP has no independent operations or material assets other than owning the partnership interests in the Partnership (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.” “MGR assets” refers to the Red Desert complex and the Granger straddle plant.
The Partnership is engaged in the business of gathering, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, natural gas liquids (“NGLs”) and crude oil; and gathering and disposing of produced water. The Partnership provides these midstream services for Anadarko, as well as for third-party producers and customers. As of September 30, 2017, the Partnership’s assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	12	3	3	2
Treating facilities	19	3	—	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), North-central Pennsylvania and Texas. During the second quarter of 2017, the Partnership commenced operation of two produced-water disposal systems in West Texas, which are included within Gathering systems in the table above. Train VI, an additional processing plant at the DBM complex, is expected to commence operations during the fourth quarter of 2017.

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]		
Marcellus Interest systems	33.75	%
Newcastle system	50	%
Springfield system	50.1	%
Full consolidation		
Chipeta [3]	75	%
DBJV system [4]	100	%

(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.

(4) The Partnership acquired an additional 50% interest in the DBJV system (the "Additional DBJV System Interest") from a third party on March 17, 2017. See Note 2.

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.
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 2016 Form 10-K, as filed with the SEC on February 23, 2017. Management believes that the disclosures made are adequate to make the information not misleading.

Presentation of Partnership assets. The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method (see Note 7) by the Partnership as of September 30, 2017. 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.

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

For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership's acquisition of the Partnership assets from Anadarko are 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.

Use of estimates. 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.

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 that are received from insurance carriers are net of any deductibles related to the covered event. A receivable is recorded from insurance to the extent a loss is recognized from an involuntary conversion event and the likelihood of recovering such loss is deemed probable. To the extent that any insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. A gain on involuntary conversion is recognized when the amount received from insurance exceeds the net book value of the retired asset(s). In addition, gains related to insurance recoveries are not recognized until all contingencies related to such proceeds have been resolved, that is, a cash payment is received from the insurance carrier or there is a binding settlement agreement with the carrier that clearly states that a 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 consolidated statements of cash flows. With respect to business interruption insurance claims, income is recognized only when cash proceeds are received from insurers, which are presented in the 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 Delaware Basin Midstream, LLC ("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 and returned to service in December 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. During the quarter ended March 31, 2017, a $5.7 million loss was recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to a change in the Partnership's estimate of the amount that would be recovered under the property insurance claim based on further discussions with insurers. During the second quarter of 2017, the Partnership reached a settlement with insurers and final proceeds were received. As of September 30, 2017, and December 31, 2016, the consolidated balance sheets include receivables of zero and $30.0 million, respectively, for the property insurance claim related to the incident at the DBM complex. During the nine months ended September 30, 2017, the Partnership received $52.9 million in cash proceeds from insurers in final settlement of the Partnership's claims related to the incident at the DBM complex, including $29.9 million in proceeds from business interruption insurance claims and

$23.0 million in proceeds from property insurance claims.

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

Recently adopted accounting standards. Accounting Standards Update (“ASU”) 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or a business. This ASU provides a screen that when substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset, or a group of similar identifiable assets, the assets will not be considered a business. If the screen is not met, the assets must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. The Partnership’s adoption of this ASU on January 1, 2017, using a prospective approach, could have a material impact on future consolidated financial statements as goodwill will not be allocated to divestitures or recorded on acquisitions that are not considered businesses.
ASU 2016-16, Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory requires an entity to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs and eliminates the exception for an intra-entity transfer of an asset other than inventory. The Partnership adopted this ASU on January 1, 2017, using a modified retrospective approach, with no impact to its consolidated financial statements.

New accounting standards issued but not yet adopted. ASU 2016-18, Statement of Cash Flows (Topic 230): Restricted Cash requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach, with early adoption permitted. The Partnership will adopt this ASU on January 1, 2018, and does not expect the adoption to have a material impact on its consolidated financial statements.
ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach if practicable, with early adoption permitted. The Partnership will adopt this ASU on January 1, 2018, and does not expect the adoption to have a material impact on its consolidated statement of cash flows.
ASU 2016-02, Leases (Topic 842) requires 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. The provisions of ASU 2016-02 also modify the definition of a lease and outline the requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The Partnership plans to elect certain practical expedients when implementing the new lease standard, which means the Partnership will not have to reassess the accounting for contracts that commenced prior to adoption. The Partnership has preliminarily determined its portfolio of leased assets and is reviewing all related contracts to determine the impact that adoption will have on its consolidated financial statements. The Partnership is also evaluating the impact of this ASU on its systems, processes, and internal controls. The Partnership will complete its evaluation in 2018 and adopt this new standard on January 1, 2019, using a modified retrospective approach for all comparative periods presented.

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

ASU 2014-09, Revenue from Contracts with Customers (Topic 606) supersedes current revenue recognition requirements and 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. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. The Partnership has completed an initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of the ASU. While the Partnership does not currently expect net income to be materially impacted, it has concluded that it is acting as an agent in the sale of certain volumes on behalf of its customers based on the requirements of the new ASU. This conclusion will result in the reduction of natural gas and natural gas liquids sales revenues and a corresponding reduction to cost of product expense related to its contracts with these customers. In addition, the Partnership expects to recognize revenue for commodities received as noncash consideration in exchange for services provided and revenue and associated cost of product expense for the subsequent sale of those same commodities. This recognition will result in an increase to revenues for gathering and processing activities and cost of product expense with no impact on net income. The Partnership expects to recognize additional revenues for certain customer contributions related to capital cost recoveries that were previously accounted for as a reduction to capitalized property, plant and equipment. The Partnership also expects changes in the timing of recognizing revenue for certain fees due to the fee structure of certain contracts. The Partnership continues to evaluate the impact of these and other provisions of the ASU on its accounting policies, internal controls, and consolidated financial statements. Although the Partnership has not finalized the quantitative impact of the new standard, based on the assessment completed to date, the Partnership does not expect the adoption of this standard will have a material impact on its net income. The Partnership will complete its evaluation during the fourth quarter of 2017 and will adopt this new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to equity and partners’ capital.

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2. ACQUISITIONS AND DIVESTITURES

The following table presents the acquisitions completed by the Partnership during 2017 and 2016, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued	Series A Preferred Units Issued
Springfield system [(1)]	03/14/2016	50.1 %	$ 247,500	$ —	2,089,602	14,030,611
DBJV system [(2)]	03/17/2017	50 %	—	155,000	—	—

(1) 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.

(2) The Partnership acquired the Additional DBJV System Interest from a third party. See Property exchange below.

Property exchange. On March 17, 2017, the Partnership acquired the Additional DBJV System Interest from a third party in exchange for (a) the Partnership's 33.75% non-operated interest in two natural gas gathering systems located in northern Pennsylvania (the "Non-Operated Marcellus Interest"), commonly referred to as the Liberty and Rome systems, and (b) $155.0 million of cash consideration (collectively, the "Property Exchange"). The Partnership previously held a 50% interest in, and operated, the DBJV system.
The Property Exchange is reflected as a nonmonetary transaction whereby the acquired Additional DBJV System Interest is recorded at the fair value of the divested Non-Operated Marcellus Interest plus the $155.0 million of cash consideration. The Property Exchange resulted in a net gain of $125.7 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. Results of operations attributable to the Property Exchange were included in the Partnership's consolidated statement of operations beginning on the acquisition date in the first quarter of 2017.

2. ACQUISITIONS AND DIVESTITURES (CONTINUED)

DBJV acquisition - Deferred purchase price obligation - Anadarko. Prior to the Partnership's agreement with Anadarko to settle its deferred purchase price obligation early, the consideration that would have been paid by the Partnership for the March 2015 acquisition of Delaware Basin JV Gathering LLC ("DBJV") from Anadarko, consisted of a cash payment to Anadarko due on March 31, 2020. The cash payment would have been 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 was defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. In May 2017, the Partnership reached an agreement with Anadarko to settle this obligation whereby the Partnership made a cash payment to Anadarko of $37.3 million, equal to the estimated net present value of the obligation at March 31, 2017.
The following table summarizes the financial statement impact of the Deferred purchase price obligation - Anadarko:

	Deferred purchase price obligation - Anadarko	Estimated future payment obligation [1]
Balance at December 31, 2016	$ 41,440	$ 56,455
Accretion expense [2]	71	
Revision to Deferred purchase price obligation – Anadarko [3]	(4,165)	
Settlement of the Deferred purchase price obligation – Anadarko	(37,346)	
Balance at September 30, 2017	$ —	$ —

(1) Calculated using Level 3 inputs.
(2) Accretion expense was recorded as a charge to Interest expense in the consolidated statements of operations.
(3) Recorded as revisions within Common units in the consolidated balance sheet and consolidated statement of equity and partners' capital.

Helper and Clawson systems divestiture. During the second quarter of 2017, the Helper and Clawson systems, located in Utah, were sold to a third party, resulting in a net gain on sale of $16.4 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

Hugoton system divestiture. During the fourth quarter of 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. The Partnership allocated $1.6 million in goodwill to this divestiture.

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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 Partnership's general partner (the "Board of Directors") 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
2016			
March 31	$ 0.815	$ 158,905	May 2016
June 30	0.830	162,827	August 2016
September 30	0.845	166,742	November 2016
December 31	0.860	170,657	February 2017
2017			
March 31	$ 0.875	$ 188,753	May 2017
June 30	0.890	207,491	August 2017
September 30 (1)	0.905	212,038	November 2017

(1) The Board of Directors declared a cash distribution to the Partnership's unitholders for the third quarter of 2017 of $0.905 per unit, or $212.0 million in aggregate, including incentive distributions, but excluding distributions on Class C units (see Class C unit distributions below). The cash distribution is payable on November 13, 2017, to unitholders of record at the close of business on November 2, 2017.

Available cash. The amount of available cash (as defined in the partnership agreement) generally is all cash on hand at the end of the quarter, plus, at the discretion of the general partner, working capital borrowings made subsequent to the end of such quarter, less the amount of cash reserves established by the Partnership's general partner to provide for the proper conduct of the Partnership's business, including reserves to fund future capital expenditures; to comply with applicable laws, debt instruments or other agreements; or to provide funds for distributions to its unitholders and to its general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. Working capital borrowings may only be those that, at the time of such borrowings, were intended to be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners.

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 March 1, 2020 (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. See Note 4 for further discussion of the Class C units.

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3. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

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 2016. The Series A Preferred unitholders received quarterly distributions in cash equal to $0.68 per Series A Preferred unit, subject to certain adjustments. The following table summarizes the Series A Preferred unitholders' cash distributions for the periods presented:

thousands except per-unit amounts

Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2016			
March 31 (1)	$ 0.68	$ 1,887	May 2016
June 30 (2)	0.68	14,082	August 2016
September 30	0.68	14,907	November 2016
December 31	0.68	14,908	February 2017
2017			
March 31	$ 0.68	$ 7,453	May 2017

(1) Quarterly per unit distribution prorated for the 18-day period during which 14,030,611 Series A Preferred units were outstanding during the first quarter of 2016.

(2) Full quarterly per unit distribution on 14,030,611 Series A Preferred units and quarterly per unit distribution prorated for the 77-day period during which 7,892,220 Series A Preferred units were outstanding during the second quarter of 2016.

On March 1, 2017, 50% of the outstanding Series A Preferred units converted into common units on a one-for-one basis, and on May 2, 2017, the remaining Series A Preferred units converted into common units on a one-for-one basis. Such converted common units were entitled to distributions made to common unitholders with respect to the quarter during which the applicable conversion occurred and did not include a prorated Series A Preferred unit distribution.

General partner interest and incentive distribution rights. As of September 30, 2017, the general partner was entitled to 1.5% of all quarterly distributions that the Partnership makes prior to its liquidation and, as the holder of the incentive distribution rights ("IDRs"), was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented, after the minimum quarterly distribution and the target distribution levels had been achieved. The maximum distribution sharing percentage of 49.5% does not include any distributions that the general partner may receive on common units that it may acquire.

4. EQUITY AND PARTNERS' CAPITAL

Class C units. In November 2014, the Partnership issued 10,913,853 Class C units to Anadarko Midstream Holdings, LLC ("AMH"), pursuant to a Unit Purchase Agreement with Anadarko and AMH. The Class C units were issued to partially fund the acquisition of DBM.

When issued, the Class C units were scheduled to convert into common units on a one-for-one basis on December 31, 2017. In February 2017, Anadarko elected to extend the conversion date of the Class C units to March 1, 2020. The Partnership can elect to convert the Class C units earlier or Anadarko can extend the conversion date again.

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, 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 is 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 the extended conversion date of March 1, 2020, using the effective yield method. The impact of the beneficial conversion feature amortization is also included in the calculation of earnings per unit.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Series A Preferred units. In 2016, the Partnership issued 21,922,831 Series A Preferred units to private investors. Pursuant to an agreement between the Partnership and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into common units on a one-for-one basis on March 1, 2017, and the remaining Series A Preferred units converted on a one-for-one basis on May 2, 2017. The Partnership has an effective registration statement with the SEC relating to the public resale of the common units issued upon conversion of the Series A Preferred units.

The Series A Preferred units were issued at a discount to the then-current market price of the common units into which they were convertible. This discount, totaling $93.4 million, represented a beneficial conversion feature, and at issuance, 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 Series A Preferred units on the date of issuance. The beneficial conversion feature was considered a non-cash distribution that was recognized from the date of issuance through the date of conversion, resulting in an increase in Series A Preferred unitholders' capital and a decrease in common unitholders' capital as amortized. The beneficial conversion feature was amortized using the effective yield method. The impact of the beneficial conversion feature amortization is also included in the calculation of earnings per unit. For the nine months ended September 30, 2017, the amortization for the beneficial conversion feature of the Series A Preferred units was $62.3 million.

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 nine months ended September 30, 2017:

	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Total
Balance at December 31, 2016	130,671,970	12,358,123	21,922,831	2,583,068	167,535,992
PIK Class C units	—	619,510	—	—	619,510
Conversion of Series A Preferred units	21,922,831	—	(21,922,831)	—	—
Long-Term Incentive Plan award vestings	7,304	—	—	—	7,304
Balance at September 30, 2017	152,602,105	12,977,633	—	2,583,068	168,162,806

Holdings of Partnership equity. As of September 30, 2017, WGP held 50,132,046 common units, representing a 29.8% 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 incentive distribution rights. As of September 30, 2017, other subsidiaries of Anadarko collectively held 2,011,380 common units and 12,977,633 Class C units, representing an aggregate 9.0% limited partner interest in the Partnership. As of September 30, 2017, the public held 100,458,679 common units, representing a 59.7% limited partner interest in the Partnership.

4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Net income (loss) per unit for common units. 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 unitholders for purposes of calculating net income (loss) per common unit. Net income (loss) attributable to Western Gas Partners, LP earned on and subsequent to the date of acquisition of the Partnership assets is allocated as follows:

General partner. The general partner's allocation is equal to cash distributions plus its portion of undistributed earnings or losses. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner consistent with actual cash distributions and capital account allocations, including incentive distributions. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner in accordance with its weighted-average ownership percentage during each period.

Series A Preferred unitholders. The Series A Preferred units were not considered a participating security as they only had distribution rights up to the specified per-unit quarterly distribution and had no rights to the Partnership's undistributed earnings and losses. As such, the Series A Preferred unitholders' allocation was equal to their cash distribution plus the amortization of the Series A Preferred units beneficial conversion feature (see Series A Preferred units above).

Common and Class C unitholders. The Class C units are considered a participating security because they participate in distributions with common units according to a predetermined formula (see Note 3). The common and Class C unitholders' allocation is equal to their cash distributions plus their respective portions of undistributed earnings or losses. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the common and Class C unitholders consistent with actual cash distributions and capital account allocations. Undistributed earnings or undistributed losses are then allocated to the common and Class C unitholders in accordance with their respective weighted-average ownership percentages during each period. The common unitholder allocation also includes the impact of the amortization of the Series A Preferred units and Class C units beneficial conversion features. The Class C unitholder allocation is similarly impacted by the amortization of the Class C units beneficial conversion feature (see Class C units above).

Calculation of net income (loss) per unit. Basic net income (loss) per common unit is calculated by dividing the 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. Diluted net income (loss) per common unit is calculated by dividing the sum of (i) the net income (loss) attributable to common units adjusted for distributions on the Series A Preferred units and a reallocation of the common and Class C limited partners' interest in net income (loss) assuming conversion of the Series A Preferred units into common units, and (ii) the net income (loss) attributable 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.

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 September 30,		Nine Months Ended September 30,	
thousands except per-unit amounts	2017	2016	2017	2016
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Pre-acquisition net (income) loss allocated to Anadarko	—	—	—	(11,326)
Series A Preferred units interest in net (income) loss [1]	—	(25,539)	(42,373)	(50,989)
General partner interest in net (income) loss	(78,376)	(60,551)	(222,903)	(174,332)
Common and Class C limited partners' interest in net income (loss)	$65,130	$81,656	$153,570	$211,680
Net income (loss) allocable to common units [1]	$57,448	$70,204	$132,545	$181,388
Net income (loss) allocable to Class C units [1]	7,682	11,452	21,025	30,292
Common and Class C limited partners' interest in net income (loss)	$65,130	$81,656	$153,570	$211,680
Net income (loss) per unit				
Common units – basic and diluted [2]	$0.38	$0.54	$0.91	$1.39
Weighted-average units outstanding				
Common units – basic and diluted	152,602	130,672	145,371	130,112
Excluded due to anti-dilutive effect:				
Class C units [2]	12,873	12,063	12,660	11,835
Series A Preferred units assuming conversion to common units [2]	—	21,923	7,227	15,160

(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 for all periods presented. As of May 2, 2017, all Series A Preferred units were converted into common units on a one-for-one basis.

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. 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 $313.2 million and $313.3 million at September 30, 2017, and December 31, 2016, 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.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in its percent-of-proceeds and keep-whole contracts. 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 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.

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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:

thousands	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Gains (losses) on commodity price swap agreements related to sales: (1)				
Natural gas sales	$6,284	$719	$12,022	$12,962
Natural gas liquids sales	(7,210)	15,939	(9,680)	56,489
Total	(926)	16,658	2,342	69,451
Gains (losses) on commodity price swap agreements related to purchases (2)	(117)	(9,248)	(2,928)	(45,032)
Net gains (losses) on commodity price swap agreements	$(1,043)	$7,410	$(586)	$24,419

(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.

Revenues or costs attributable to volumes settled during 2016 and 2017 for the DJ Basin complex and 2017 for the MGR assets are recognized in the consolidated statements of operations at the applicable market price in the tables below. The Partnership also records 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 tables below. The commodity price swap agreement for the Hugoton system was in place until its divestiture in October 2016. For the nine months ended September 30, 2017, the capital contribution from Anadarko was $46.7 million. The tables below summarize the swap prices compared to the forward market prices:

	DJ Basin Complex		
per barrel except natural gas	2016 - 2017 Swap Prices	2016 Market Prices (1)	2017 Market Prices (1)
Ethane	$18.41	$ 0.60	$ 5.09
Propane	47.08	10.98	18.85
Isobutane	62.09	17.23	26.83
Normal butane	54.62	16.86	26.20
Natural gasoline	72.88	26.15	41.84
Condensate	76.47	34.65	45.40
Natural gas (per MMBtu)	5.96	2.11	3.05

(1) Represents the New York Mercantile Exchange ("NYMEX") forward strip price as of December 8, 2015 and December 1, 2016, for the 2016 Market Prices and 2017 Market Prices, respectively, 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)

	MGR Assets	
per barrel except natural gas	2016 - 2017 Swap Prices	2017 Market Prices (1)
Ethane	$23.11	$ 4.08
Propane	52.90	19.24
Isobutane	73.89	25.79
Normal butane	64.93	25.16
Natural gasoline	81.68	45.01
Condensate	81.68	53.55
Natural gas (per MMBtu)	4.87	3.05

(1) Represents the NYMEX forward strip price as of December 1, 2016, adjusted for product specification, location, basis and, in the case of NGLs, transportation and fractionation costs.

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 natural gas gathering, treating and transportation throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 33% and 34% for the three and nine months ended September 30, 2017, respectively, and 37% and 38% for the three and nine months ended September 30, 2016, respectively. The Partnership's natural gas processing throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 39% and 42% for the three and nine months ended September 30, 2017, respectively, and 51% and 55% for the three and nine months ended September 30, 2016, respectively. The Partnership's crude, NGL and produced water gathering, treating and transportation throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 54% and 50% for the three and nine months ended September 30, 2017, respectively, and 67% and 64% for the three and nine months ended September 30, 2016, respectively.

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.

Acquisitions from Anadarko. On March 14, 2016, the Partnership acquired Springfield from Anadarko (see Note 2).

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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 September 30, 2017 and 2016, and \$0.3 million for each of the nine months ended September 30, 2017 and 2016.

WGP LTIP and Anadarko Incentive Plan. General and administrative expenses included \$1.2 million and \$3.2 million for the three and nine months ended September 30, 2017, respectively, and \$1.4 million and \$3.7 million for the three and nine months ended September 30, 2016, 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 2012 Omnibus Incentive Compensation Plan ("Anadarko Incentive Plan"). Of this amount, \$3.3 million is reflected as contributions to partners' capital in the Partnership's consolidated statement of equity and partners' capital for the nine months ended September 30, 2017.

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

	Nine Months Ended September 30,			
	2017	2016	2017	2016
thousands	Purchases		Sales	
Cash consideration	$3,910	$3,965	$—	$623
Net carrying value	(5,283)	(3,366)	—	(605)
Partners' capital adjustment	$(1,373)	$599	$—	$18

Contributions in aid of construction costs from affiliates. On certain of the Partnership's capital projects, Anadarko is obligated to reimburse the Partnership for all or a portion of project capital expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. The cash receipts resulting from such reimbursements are presented as "Contributions in aid of construction costs from affiliates" within the investing section of the Partnership's consolidated statements of cash flows.

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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 September 30,		Nine Months Ended September 30,	
thousands	2017	2016	2017	2016
Revenues and other [1]	$351,127	$325,312	$982,595	$900,301
Equity income, net – affiliates [1]	21,519	20,294	62,708	56,801
Cost of product [1]	22,902	21,254	60,497	67,979
Operation and maintenance [2]	18,110	15,052	53,661	50,688
General and administrative [3]	10,140	9,453	29,040	27,574
Operating expenses	51,152	45,759	143,198	146,241
Interest income [4]	4,225	4,225	12,675	12,675
Interest expense [5]	—	(1,173)	71	(12,097)
Settlement of the Deferred purchase price obligation – Anadarko [6]	—	—	(37,346)	—
Proceeds from the issuance of common units, net of offering expenses [7]	—	—	—	25,000
Distributions to unitholders [8]	118,082	97,648	331,654	282,326
Above-market component of swap agreements with Anadarko	18,049	18,417	46,719	34,782

(1) Represents amounts earned or incurred on and subsequent to the date of the acquisition of 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 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 Plan within this Note 5).

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

(5) Includes amounts related to the Deferred purchase price obligation - Anadarko (see Note 2 and Note 9).

(6) Represents the cash payment to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko (see Note 2).

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

(8) 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	September 30, 2017	December 31, 2016
Land	n/a	$4,271	$ 4,012
Gathering systems and processing complexes	3 to 47 years	6,972,302	6,462,053
Pipelines and equipment	15 to 45 years	139,344	139,646
Assets under construction	n/a	434,432	226,626
Other	3 to 40 years	31,829	29,605
Total property, plant and equipment		7,582,178	6,861,942
Accumulated depreciation		2,074,464	1,812,010
Net property, plant and equipment		$5,507,714	$ 5,049,932

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.

Impairments. During the nine months ended September 30, 2017, the Partnership recognized impairments of $170.1 million, including an impairment of $158.8 million at the Granger complex, which was impaired to its estimated fair value of $48.5 million using the income approach and Level 3 fair value inputs, due to a reduced throughput fee as a result of a producer’s bankruptcy. Also during the period, the Partnership recognized additional impairments of $11.3 million, primarily related to (i) a $3.7 million impairment at the Granger straddle plant, which was impaired to its estimated salvage value of $0.6 million using the income approach and Level 3 fair value inputs, (ii) a $3.1 million impairment of the Fort Union equity investment (see Note 7), (iii) a $2.0 million impairment of an idle facility in northeast Wyoming, which was impaired to its estimated salvage value of $0.4 million using the market approach and Level 3 fair value inputs, and (iv) the cancellation of a pipeline project in West Texas.
During 2016, the Partnership recognized impairments of $15.5 million, including an impairment of $6.1 million 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. Also during 2016, the Partnership recognized impairments of $9.4 million, primarily related to the cancellation of projects at the DJ Basin complex and Springfield and DBJV systems, and the abandonment of compressors at the MIGC system.

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7. EQUITY INVESTMENTS

The following table presents the activity in the Partnership’s equity investments for the nine months ended September 30, 2017:

	Equity Investments							
thousands	Fort Union	White Cliffs	Rendezvous	Mont Belvieu JV	TEG	TEP	FRP	Total
Balance at December 31, 2016	$12,833	$47,319	$ 46,739	$112,805	$15,846	$189,194	$169,472	$594,208
Investment earnings (loss), net of amortization	2,964	9,984	840	20,430	2,325	13,332	12,833	62,708
Impairment expense [(1)]	(3,110)	—	—	—	—	—	—	(3,110)
Contributions	—	277	—	—	—	107	—	384
Distributions	(3,359)	(9,548)	(2,296)	(20,459)	(2,167)	(13,520)	(12,964)	(64,313)
Distributions in excess of cumulative earnings [(2)]	(1,662)	(2,325)	(1,616)	(2,316)	—	(6,091)	(2,245)	(16,255)
Balance at September 30, 2017	$7,666	$45,707	$ 43,667	$110,460	$16,004	$183,022	$167,096	$573,622

(1) Recorded in Impairments in the consolidated statements of operations.
(2) 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.

The investment balance in Fort Union at September 30, 2017, is $3.1 million less than the Partnership’s underlying equity in Fort Union’s net assets due to an impairment loss recognized by the Partnership in the second quarter of 2017 for its investment in Fort Union. This investment was impaired to its estimated fair value of $8.5 million, using the income approach and Level 3 fair value inputs.

8. COMPONENTS OF WORKING CAPITAL

A summary of accounts receivable, net is as follows:

thousands	September 30, 2017	December 31, 2016
Trade receivables, net	$ 192,487	$ 192,808
Other receivables, net	43	30,415
Total accounts receivable, net	$ 192,530	$ 223,223

A summary of other current assets is as follows:

thousands	September 30, 2017	December 31, 2016
Natural gas liquids inventory	$ 8,459	$ 7,126
Imbalance receivables	2,103	3,483
Prepaid insurance	2,819	2,257
Total other current assets	$ 13,381	$ 12,866

A summary of accrued liabilities is as follows:

thousands	September 30, 2017	December 31, 2016
Accrued interest expense	$ 45,616	$ 39,826
Short-term asset retirement obligations	3,976	3,114
Short-term remediation and reclamation obligations	630	630
Income taxes payable	1,024	1,006
Other	6,250	532
Total accrued liabilities	$ 57,496	$ 45,108

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9. DEBT AND INTEREST EXPENSE

At September 30, 2017, 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"), 4.650% Senior Notes due 2026 (the "2026 Notes") and borrowings on the RCF.
The following table presents the Partnership's outstanding debt as of September 30, 2017, and December 31, 2016:

	September 30, 2017			December 31, 2016		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
2021 Notes	$500,000	$495,541	$536,712	$500,000	$494,734	$536,252
2022 Notes	670,000	668,795	693,789	670,000	668,634	681,723
2018 Notes	350,000	349,558	351,770	350,000	349,188	351,531
2044 Notes	600,000	593,206	634,283	600,000	593,132	615,753
2025 Notes	500,000	491,653	503,322	500,000	490,971	492,499
2026 Notes	500,000	495,133	525,069	500,000	494,802	518,441
RCF	250,000	250,000	250,000	—	—	—
Total long-term debt	$3,370,000	$3,343,886	$3,494,945	$3,120,000	$3,091,461	$3,196,199

[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 nine months ended September 30, 2017:

thousands	Carrying Value
Balance at December 31, 2016	$ 3,091,461
RCF borrowings	250,000
Other	2,425
Balance at September 30, 2017	$ 3,343,886

Senior Notes. The 2018 Notes, which are due in August 2018, were classified as long-term debt on the consolidated balance sheet at September 30, 2017, as the Partnership has the ability and intent to refinance these obligations using long-term debt. At September 30, 2017, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.

Revolving credit facility. As of September 30, 2017, the Partnership had $250.0 million of outstanding RCF borrowings and $4.6 million in outstanding letters of credit, resulting in $945.4 million available for borrowing under the RCF, which matures in February 2020. As of September 30, 2017 and 2016, the interest rate on the outstanding RCF borrowings was 2.54% and 1.82%, respectively. The facility fee rate was 0.20% at September 30, 2017 and 2016. At September 30, 2017, the Partnership was in compliance with all covenants under the RCF.

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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 September 30,		Nine Months Ended September 30,	
thousands	2017	2016	2017	2016
Third parties				
Long-term debt	$(35,992)	$(31,612)	$(105,772)	$(87,711)
Amortization of debt issuance costs and commitment fees	(1,667)	(1,672)	(4,942)	(4,747)
Capitalized interest	2,115	1,343	3,991	4,674
Total interest expense – third parties	(35,544)	(31,941)	(106,723)	(87,784)
Affiliates				
Deferred purchase price obligation – Anadarko[1]	—	1,173	(71)	12,097
Total interest expense – affiliates	—	1,173	(71)	12,097
Interest expense	$(35,544)	$(30,768)	$(106,794)	$(75,687)

[1] See Note 2 for a discussion 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 September 30, 2017, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $143.3 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to expansion projects at the DBJV system and the DJ Basin and DBM complexes.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease arrangements for corporate offices, shared field offices and a warehouse supporting the Partnership's operations, and equipment leases for which Anadarko charges the Partnership rent. The leases for the corporate offices and shared field offices extend through 2028 and 2033, respectively, and the lease for the warehouse expired in February 2017.
Rent expense associated with office, warehouse and equipment leases was $11.3 million and $30.7 million for the three and nine months ended September 30, 2017, respectively, and $8.9 million and $26.2 million for the three and nine months ended September 30, 2016, 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 under Part II, Item 8 of our 2016 Form 10-K as filed with the SEC on February 23, 2017.

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 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 price of, oil, natural gas, NGLs and related products or services;
- 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;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, internationally, domestically or in the jurisdictions in which we are doing business;

- federal, state and local laws, including those that limit Anadarko 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;
- 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 from Anadarko or third parties, and Anadarko’s ability to generate an inventory of assets suitable for acquisition;
- 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;
- the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigation by the National Transportation Safety Board (“NTSB”), related to Anadarko’s operations in Colorado, and continued or additional disruptions in operations that may occur as Anadarko and we comply with regulatory orders or other state or local changes in laws or regulations in Colorado; and
- other factors discussed below, in “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates” included in our 2016 Form 10-K, and 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), North-central Pennsylvania and Texas. We are engaged in the business of gathering, compressing, treating, processing and transporting natural gas; gathering, stabilizing and transporting condensate, NGLs and crude oil; and gathering and disposing of produced water. We provide these midstream services for Anadarko, as well as for third-party producers and customers. As of September 30, 2017, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	12	3	3	2
Treating facilities	19	3	—	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 nine months ended September 30, 2017, included the following:

- In March 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration, resulting in a net gain of $125.7 million. See Acquisitions and Divestitures within this Item 2 for additional information.

- In May 2017, we reached an agreement with Anadarko to settle the outstanding Deferred purchase price obligation - Anadarko, whereby we made a cash payment to Anadarko of $37.3 million during the second quarter of 2017.

- On March 1, 2017, 50% of the outstanding Series A Preferred units converted into common units on a one-for-one basis, and on May 2, 2017, the remaining Series A Preferred units converted into common units on a one-for-one basis. See Equity Offerings within this Item 2 for additional information.

- During the second quarter of 2017, we commenced operation of the DBM water systems (included within Gathering systems in the table above).

- In June 2017, we closed on the sale of our Helper and Clawson systems, which resulted in a net gain on divestiture of $16.4 million. See Acquisitions and Divestitures within this Item 2 for additional information.

- In February 2017, Anadarko elected to extend the conversion date of the Class C units from December 31, 2017, to March 1, 2020.

- We received $52.9 million in cash proceeds from insurers in final settlement of our claims related to the incident at the DBM complex, including $29.9 million for business interruption insurance claims and $23.0 million for property insurance claims. See Liquidity and Capital Resources within this Item 2 for additional information.

- We raised our distribution to $0.905 per unit for the third quarter of 2017, representing a 2% increase over the distribution for the second quarter of 2017 and a 7% increase over the distribution for the third quarter of 2016.

-

Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,427 MMcf/d and 3,610 MMcf/d for the three and nine months ended September 30, 2017, respectively, representing a 16% and 8% decrease, respectively, compared to the same periods in 2016.

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- Throughput for crude, NGL and produced water assets totaled 209 MBbls/d and 187 MBbls/d for the three and nine months ended September 30, 2017, respectively, representing a 13% and 1% increase, respectively, compared to the same periods in 2016.

- Operating income (loss) was $179.5 million and $525.5 million for the three and nine months ended September 30, 2017, respectively, representing a 9% decrease and 0% change, respectively, compared to the same periods in 2016.

- 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 $0.97 per Mcf and $0.92 per Mcf for the three and nine months ended September 30, 2017, respectively, representing an 18% and 12% increase, respectively, compared to the same periods in 2016.

- Adjusted gross margin for crude, NGL and produced water 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 nine months ended September 30, 2017, respectively, representing an 8% and 2% decrease, respectively, compared to the same periods in 2016.

Anadarko’s Colorado Response. Following a home explosion in Firestone, Colorado in April 2017, Anadarko took precautionary measures to shut in all operated vertical wells in the DJ Basin to conduct additional inspections. It subsequently tested and permanently plugged, abandoned, and capped all one-inch return lines associated with these wells. In May 2017, the Colorado Oil & Gas Conservation Commission (“COGCC”) issued a two-phase Notice to Operators (“NTO”) requiring all operators to inventory and integrity test existing flowlines within 1,000 feet of a building unit and abandon all inactive flowlines in such areas. During the third quarter, Anadarko substantially completed the requirements of the NTO. In August 2017, following a three-month review of oil and gas operations, the Governor of Colorado announced several policy initiatives designed to enhance public safety, which are to be implemented over the next several months through rulemaking or legislation. Anadarko continues to work cooperatively with state regulators and others and is also cooperating with the NTSB in its investigation related to the incident.

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 and returned to service in December 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 is 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.

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ACQUISITIONS AND DIVESTITURES

Acquisitions. The following table presents the acquisitions completed during 2017 and 2016, 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	Borrowings	Cash On Hand	Common Units Issued	Series A Preferred Units Issued
Springfield system [1]	03/14/2016	50.1 %	$ 247,500	$ —	2,089,602	14,030,611
DBJV system [2]	03/17/2017	50 %	—	155,000	—	—

(1) 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 further information regarding the Series A Preferred units.

(2) We acquired the Additional DBJV System Interest from a third party. See Property exchange below.

Property exchange. On March 17, 2017, we acquired the Additional DBJV System Interest from a third party in exchange for the Non-Operated Marcellus Interest and $155.0 million of cash consideration. We previously held a 50% interest in, and operated, the DBJV system. The Property Exchange resulted in a net gain of $125.7 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.
See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Divestitures. During the second quarter of 2017, the Helper and Clawson systems, located in Utah, were sold to a third party, resulting in a net gain on sale of $16.4 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.
During the fourth quarter of 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

Presentation of Partnership assets. The term "Partnership assets" includes both the assets owned and the interests accounted for under the equity method (see Note 7—Equity Investments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q) by us as of September 30, 2017. 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.

EQUITY OFFERINGS

Series A Preferred units. In 2016, we issued 21,922,831 Series A Preferred units to private investors. Pursuant to an agreement between us and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into common units on a one-for-one basis on March 1, 2017, and the remaining Series A Preferred units converted on a one-for-one basis on May 2, 2017. 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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RESULTS OF OPERATIONS

OPERATING RESULTS

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

thousands	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Total revenues and other [1]	$574,695	$481,645	$1,616,338	$1,293,450
Equity income, net – affiliates	21,519	20,294	62,708	56,801
Total operating expenses [1]	416,830	312,088	1,318,489	830,699
Gain (loss) on divestiture and other, net	72	(6,230)	135,017	(8,769)
Proceeds from business interruption insurance claims [2]	—	13,667	29,882	16,270
Operating income (loss)	179,456	197,288	525,456	527,053
Interest income – affiliates	4,225	4,225	12,675	12,675
Interest expense	(35,544)	(30,768)	(106,794)	(75,687)
Other income (expense), net	286	153	969	224
Income (loss) before income taxes	148,423	170,898	432,306	464,265
Income tax (benefit) expense	510	472	4,905	7,431
Net income (loss)	147,913	170,426	427,401	456,834
Net income attributable to noncontrolling interest	4,407	2,680	8,555	8,507
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Key performance metrics [3]				
Adjusted gross margin attributable to Western Gas Partners, LP	$344,416	$343,981	$1,009,520	$984,459
Adjusted EBITDA attributable to Western Gas Partners, LP	257,835	278,170	787,664	759,834
Distributable cash flow	231,859	237,315	695,587	628,602

(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 these non-GAAP financial measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, see Key Performance Metrics–Reconciliation of non-GAAP measures within this Item 2.

For purposes of the following discussion, any increases or decreases “for the three months ended September 30, 2017” refer to the comparison of the three months ended September 30, 2017, to the three months ended September 30, 2016; any increases or decreases “for the nine months ended September 30, 2017” refer to the comparison of the nine months ended September 30, 2017, to the nine months ended September 30, 2016; and any increases or decreases “for the three and nine months ended September 30, 2017” refer to the comparison of these 2017 periods to the corresponding three and nine month periods ended September 30, 2016.

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Throughput

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)						
Gathering, treating and transportation	784	1,562	(50)%	1,029	1,556	(34)%
Processing	2,588	2,448	6 %	2,528	2,301	10 %
Equity investment [1]	159	179	(11)%	160	178	(10)%
Total throughput for natural gas assets	3,531	4,189	(16)%	3,717	4,035	(8)%
Throughput attributable to noncontrolling interest for natural gas assets	104	119	(13)%	107	127	(16)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,427	4,070	(16)%	3,610	3,908	(8)%
Throughput for crude, NGL and produced water assets (MBbls/d)						
Gathering, treating and transportation	77	58	33 %	57	59	(3)%
Equity investment [2]	132	127	4 %	130	126	3 %
Total throughput for crude, NGL and produced water assets	209	185	13 %	187	185	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 778 MMcf/d and 527 MMcf/d for the three and nine months ended September 30, 2017, respectively, primarily due to the Property Exchange in March 2017 (decreases of 594 MMcf/d and 341 MMcf/d, respectively), production declines in the areas around the Marcellus Interest (decreases of 38 MMcf/d and 52 MMcf/d, respectively) and Springfield gas gathering systems (decreases of 40 MMcf/d and 47 MMcf/d, respectively), and the sale of the Hugoton system in October 2016 (decreases of 52 MMcf/d and 54 MMcf/d, respectively).

Processing throughput increased by 140 MMcf/d and 227 MMcf/d for the three and nine months ended September 30, 2017, respectively, primarily due to the DBM outage in 2016 and the start-up of Train IV and Train V at the DBM complex in May 2016 and October 2016, respectively. These increases were partially offset by production declines in the areas around the Chipeta complex and MGR assets.

Equity investment throughput decreased by 20 MMcf/d and 18 MMcf/d for the three and nine months ended September 30, 2017, respectively, due to decreased throughput at the Rendezvous and Fort Union systems due to production declines in the area.

Crude, NGL and produced water assets

Gathering, treating and transportation throughput increased by 19 MBbls/d for the three months ended September 30, 2017, primarily due to the start-up of operations at the DBM water systems during the second quarter of 2017, partially offset by decreased throughput at the Springfield oil gathering system due to production declines in the area.

Gathering, treating and transportation throughput decreased by 2 MBbls/d for the nine months ended September 30, 2017, primarily due to decreased throughput at the Springfield oil gathering system due to production declines in the area, partially offset by throughput from the DBM water systems that commenced operation during the second quarter of 2017.

Equity investment throughput increased by 5 MBbls/d and 4 MBbls/d for the three and nine months ended September 30, 2017, respectively, primarily due to increased volumes on FRP and TEG as a result of increased NGL production and an increase at the Mont Belvieu JV due to higher inlet throughput. These increases were partially offset by decreased throughput at White Cliffs as a result of a competitive pipeline commencing service in September 2016.

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Gathering, Processing and Transportation Revenues

thousands except percentages	Three Months Ended September 30, 2017	2016	Inc/ (Dec)	Nine Months Ended September 30, 2017	2016	Inc/ (Dec)
Gathering, processing and transportation revenues	$306,187	$315,192	(3)%	$913,436	$910,332	— %

Revenues from gathering, processing and transportation decreased by $9.0 million for the three months ended September 30, 2017, primarily due to decreases of (i) $15.4 million due to the Property Exchange in March 2017, (ii) $7.4 million at the Springfield system, $2.6 million at the Chipeta complex and $1.6 million at the Marcellus Interest systems in each case due to throughput decreases, (iii) $4.7 million due to the sale of the Hugoton system in October 2016 and (iv) $2.8 million at the Granger complex due to a lower processing fee. These decreases were partially offset by increases of (i) $16.2 million at the DBM complex due to increased throughput (see Operating Results–Throughput within this Item 2), (ii) $8.5 million at the DJ Basin complex due to increased throughput and a higher throughput fee and (iii) $3.0 million at the DBM water systems that commenced operation during the second quarter of 2017. Revenues from gathering, processing and transportation increased by $3.1 million for the nine months ended September 30, 2017, primarily due to increases of (i) $72.6 million at the DBM complex due to increased throughput (see Operating Results–Throughput within this Item 2), (ii) $23.1 million at the DJ Basin complex due to increased throughput and a higher throughput fee and (iii) $4.1 million at the DBM water systems that commenced operation during the second quarter of 2017. These increases were partially offset by decreases of (i) $25.7 million at the Springfield system, $10.8 million at the Chipeta complex and $7.6 million at the Marcellus Interest systems in each case due to throughput decreases, (ii) $28.5 million due to the Property Exchange in March 2017, (iii) $14.4 million due to the sale of the Hugoton system in October 2016 and (iv) $7.0 million at the Granger complex due to a lower processing fee.

Natural Gas and Natural Gas Liquids Sales

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2017	2016	Inc/ (Dec)	Nine Months Ended September 30, 2017	2016	Inc/ (Dec)
Natural gas sales [1]	$100,395	$72,658	38 %	$273,256	$155,251	76 %
Natural gas liquids sales [1]	158,746	91,378	74 %	417,234	224,334	86 %
Total	$259,141	$164,036	58 %	$690,490	$379,585	82 %
Average price per unit [1]:						
Natural gas (per Mcf)	$2.89	$2.70	7 %	$2.96	$2.41	23 %
Natural gas liquids (per Bbl)	22.99	19.10	20 %	21.63	19.45	11 %

(1) Excludes amounts considered above market with respect to our swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016) that were recorded as capital contributions in the consolidated 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 nine months ended September 30, 2017, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the MGR assets and DJ Basin complex. For the three and nine months ended September 30, 2016, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the Hugoton system, MGR assets and 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 increase in natural gas sales of $27.7 million for the three months ended September 30, 2017, was primarily due to increases of (i) $15.6 million at the DJ Basin complex due to an increase in the swap market price and volumes sold and (ii) $14.8 million at the DBM complex due to an increase in volumes sold (see Operating Results–Throughput within this Item 2). These increases were partially offset by a decrease of $3.0 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

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The increase in natural gas sales of $118.0 million for the nine months ended September 30, 2017, was primarily due to increases of (i) $75.2 million at the DBM complex due to an increase in average price and volumes sold (see Operating Results–Throughput within this Item 2), (ii) $44.3 million at the DJ Basin complex due to an increase in the swap market price and volumes sold and (iii) $4.8 million at the Hilight system due to an increase in average price. These increases were partially offset by a decrease of $9.2 million at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.
The increase in NGLs sales of $67.4 million and $192.9 million for the three and nine months ended September 30, 2017, respectively, was primarily due to increases of (i) $62.7 million and $184.5 million, respectively, at the DBM complex due to an increase in average price and volumes sold (see Operating Results–Throughput within this Item 2), (ii) $15.9 million and $38.1 million, respectively, at the DJ Basin complex due to an increase in the swap market price and volumes sold and (iii) $3.3 million and $11.3 million, respectively, at the Hilight system due to an increase in average price. These increases were partially offset by decreases during the three and nine months ended September 30, 2017, of $17.7 million and $49.9 million, respectively, at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

Other Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
Other revenues	$9,367	$2,417	NM	$12,412	$3,533	NM

NM-Not Meaningful

For the three and nine months ended September 30, 2017, other revenues increased by $7.0 million and $8.9 million, respectively, primarily due to deficiency fees at the Chipeta complex.

Equity Income, Net – Affiliates

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
Equity income, net – affiliates	$21,519	$20,294	6 %	$62,708	$56,801	10 %

For the three and nine months ended September 30, 2017, equity income, net – affiliates increased by $1.2 million and $5.9 million, respectively, primarily due to an increase in equity income from the Mont Belvieu JV due to increased volumes processed. In addition, for the nine months ended September 30, 2017, equity income, net – affiliates increased due to our 14.81% share of an impairment loss determined by the managing partner of Fort Union in the first quarter of 2016.

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Cost of Product and Operation and Maintenance Expenses

thousands except percentages	Three Months Ended September 30, 2017	2016	Inc/ (Dec)	Nine Months Ended September 30, 2017	2016	Inc/ (Dec)
NGL purchases [(1)]	$136,636	$66,822	104%	$359,616	$149,547	140 %
Residue purchases [(1)]	90,264	70,376	28 %	256,387	156,774	64 %
Other	12,323	8,445	46 %	15,856	20,638	(23)%
Cost of product	239,223	145,643	64 %	631,859	326,959	93 %
Operation and maintenance	79,536	74,755	6 %	229,444	226,141	1 %
Total cost of product and operation and maintenance expenses	$318,759	$220,398	45 %	$861,303	$553,100	56 %

(1) Excludes amounts considered above market with respect to our swap agreements for the MGR assets, DJ Basin complex and Hugoton system (until its divestiture in October 2016) that were recorded as capital contributions in the consolidated 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 nine months ended September 30, 2017, included the effects of commodity price swap agreements attributable to purchases for the MGR assets and DJ Basin complex. Cost of product expense for the three and nine months ended September 30, 2016, included the effects of commodity price swap agreements attributable to purchases for the Hugoton system, MGR assets and 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 increased by $69.8 million and $210.1 million for the three and nine months ended September 30, 2017, respectively, primarily due to increases of (i) $61.4 million and $177.1 million, respectively, at the DBM complex due to an increase in average price and volumes purchased (see Operating Results–Throughput within this Item 2), (ii) $13.2 million and $43.2 million, respectively, at the DJ Basin complex due to an increase in the swap market price and volumes purchased and (iii) $2.7 million and $9.2 million, respectively, at the Hilight system due to an increase in average price, partially offset by a decrease in volumes purchased. These increases were partially offset by decreases during the three and nine months ended September 30, 2017, of $9.5 million and $26.6 million, respectively, at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

Residue purchases increased by $19.9 million and $99.6 million for the three and nine months ended September 30, 2017, respectively, primarily due to increases of (i) $12.6 million and $68.7 million, respectively, at the DBM complex due to an increase in average price and volumes purchased (see Operating Results–Throughput within this Item 2) and (ii) $12.3 million and $36.5 million, respectively, at the DJ Basin complex due to an increase in the swap market price and volumes purchased. In addition, for the nine months ended September 30, 2017, there was an increase of $4.6 million at the Hilight system due to an increase in average price. These increases were partially offset by decreases during the three and nine months ended September 30, 2017, of $3.9 million and $12.0 million, respectively, at the MGR assets due to the partial equity treatment of the above-market swap agreement beginning January 1, 2017.

Other items increased by $3.9 million for the three months ended September 30, 2017, primarily due to changes in affiliate contract terms at the DJ Basin complex. Other items decreased by $4.8 million for the nine months ended September 30, 2017, primarily due to fees paid in 2016 for rerouting volumes due to the DBM outage, partially offset by changes in affiliate contract terms at the DJ Basin complex in 2017.

Operation and maintenance expense increased by $4.8 million for the three months ended September 30, 2017, primarily due to increases of (i) $2.6 million due to the Property Exchange in March 2017, (ii) $1.4 million in utilities expense primarily at the DJ Basin and DBM complexes and (iii) $1.4 million in salaries and wages primarily at the Springfield system. Operation and maintenance expense increased by $3.3 million for the nine months ended

September 30, 2017, primarily due to an increase of $3.0 million due to the Property Exchange in March 2017.

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Other Operating Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
General and administrative	$12,158	$11,382	7 %	$35,402	$33,542	6 %
Property and other taxes	11,215	10,670	5 %	35,433	33,098	7 %
Depreciation and amortization	72,539	67,246	8 %	216,272	199,646	8 %
Impairments	2,159	2,392	(10)%	170,079	11,313	NM
Total other operating expenses	$98,071	$91,690	7 %	$457,186	$277,599	65 %

NM-Not Meaningful

General and administrative expenses increased by $0.8 million and $1.9 million for the three and nine months ended September 30, 2017, respectively, primarily due to increases in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement and bad debt expense, partially offset by decreases in legal and consulting fees.
Property and other taxes increased by $0.5 million for the three months ended September 30, 2017, primarily due to an ad valorem tax increase at the DJ Basin complex, partially offset by a decrease at the DBM complex. Property and other taxes increased by $2.3 million for the nine months ended September 30, 2017, primarily due to ad valorem tax increases at the DBM complex and DBJV system.
Depreciation and amortization expense increased by $5.3 million and $16.6 million for the three and nine months ended September 30, 2017, respectively, primarily due to depreciation expense increases of (i) $5.2 million and $10.3 million, respectively, due to the Property Exchange in March 2017, (ii) $2.4 million and $9.1 million, respectively, related to capital projects at the DBM complex and (iii) $2.8 million and $8.4 million, respectively, at the Bison facility due to a change in the estimated property life. These increases were partially offset by decreases during the three and nine months ended September 30, 2017, of (i) $1.4 million and $5.4 million, respectively, due to the sale of the Hugoton system in October 2016, (ii) $2.4 million and $4.9 million, respectively, at the Granger complex due to an impairment recorded in the first quarter of 2017 (see impairment expense below) and (iii) $1.6 million and $2.4 million, respectively, at the DJ Basin complex due to a change in estimated salvage values.
Impairment expense decreased by $0.2 million for the three months ended September 30, 2017, primarily due to a $2.0 million impairment of an idle facility in northeast Wyoming (see Note 6—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q), as compared to impairments in 2016 primarily related to the cancellation of projects at the DBJV and Marcellus Interest systems.
Impairment expense increased by $158.8 million for the nine months ended September 30, 2017, primarily due to the following items occurring in 2017 (i) a $158.8 million impairment at the Granger complex, (ii) a $3.7 million impairment at the Granger straddle plant, (iii) a $3.1 million impairment at the Fort Union system, (iv) a $2.0 million impairment of an idle facility in northeast Wyoming and (v) the cancellation of a pipeline project in West Texas.
Impairment expense for the nine months ended September 30, 2016, was primarily due to (i) a $6.1 million impairment at the Newcastle system, (ii) the cancellation of projects at the DJ Basin complex and DBJV system and (iii) the abandonment of compressors at the MIGC system. See Note 6—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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Interest Income – Affiliates and Interest Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
Note receivable – Anadarko	$4,225	$4,225	— %	$12,675	$12,675	— %
Interest income – affiliates	$4,225	$4,225	— %	$12,675	$12,675	— %
Third parties						
Long-term debt	$(35,992)	$(31,612)	14 %	$(105,772)	$(87,711)	21 %
Amortization of debt issuance costs and commitment fees	(1,667)	(1,672)	— %	(4,942)	(4,747)	4 %
Capitalized interest	2,115	1,343	57 %	3,991	4,674	(15)%
Affiliates						
Deferred purchase price obligation – Anadarko[1]	—	1,173	(100)%	(71)	12,097	(101)%
Interest expense	$(35,544)	$(30,768)	16 %	$(106,794)	$(75,687)	41 %

(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 Deferred purchase price obligation - Anadarko.

Interest expense increased by $4.8 million and $31.1 million for the three and nine months ended September 30, 2017, respectively, primarily due to (i) accretion revisions in 2016 recorded as reductions to interest expense for 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), (ii) interest incurred on the 2026 Notes issued in July 2016 and (iii) interest incurred on the additional 2044 Notes issued in October 2016. These increases were partially offset during the nine months ended September 30, 2017, by additional interest incurred on the RCF in 2016 as a result of higher outstanding borrowings. Capitalized interest increased by $0.8 million for the three months ended September 30, 2017, primarily due to the construction of Train VI beginning in the fourth quarter of 2016 and the purchase of long-lead items associated with the Mentone plant, partially offset by a decrease primarily due to the completion of Train V in October 2016, all located at the DBM complex. Capitalized interest decreased by $0.7 million for the nine months ended September 30, 2017, primarily due to the completion of Trains IV and V in May 2016 and October 2016, respectively, partially offset by an increase due to the construction of Train VI beginning in the fourth quarter of 2016 and the purchase of long-lead items associated with the Mentone plant, all located 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 September 30,			Nine Months Ended September 30,		
thousands except percentages	2017	2016	Inc/ (Dec)	2017	2016	Inc/ (Dec)
Income (loss) before income taxes	$148,423	$170,898	(13)%	$432,306	$464,265	(7)%
Income tax (benefit) expense	510	472	8 %	4,905	7,431	(34)%
Effective tax rate	— %	— %		1 %	2 %	

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 nine months ended September 30, 2016, the variance from the federal statutory rate was 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. For all other periods presented, the variance from the federal statutory rate, which is zero percent as a non-taxable entity, was primarily due to our share of Texas margin tax.

Income attributable to the Springfield system prior to and including February 2016 was subject to federal and state income tax. Income earned on the Springfield system for periods subsequent to February 2016 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 September 30, 2017	2016	Inc/ (Dec)	Nine Months Ended September 30, 2017	2016	Inc/ (Dec)
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (1)	$305,337	$306,393	— %	$904,620	$877,583	3 %
Adjusted gross margin for crude, NGL and produced water assets (2)	39,079	37,588	4 %	104,900	106,876	(2)%
Adjusted gross margin attributable to Western Gas Partners, LP (3)	344,416	343,981	— %	1,009,520	984,459	3 %
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (4)	0.97	0.82	18 %	0.92	0.82	12 %
Adjusted gross margin per Bbl for crude, NGL and produced water assets (5)	2.03	2.20	(8)%	2.05	2.10	(2)%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	257,835	278,170	(7)%	787,664	759,834	4 %
Distributable cash flow (3)	231,859	237,315	(2)%	695,587	628,602	11 %

(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 and produced water assets is calculated as total revenues and other for crude, NGL and produced water assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for crude, NGL and produced water 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 and produced water 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 and produced water assets, divided by total throughput (MBbls/d) for crude, NGL and produced water 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 investments 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 $0.4 million and $25.1 million for the three and nine months ended September 30, 2017, respectively, primarily due to (i) an increase in throughput at the DBM complex, (ii) an increase in processed volumes at the DJ Basin complex and (iii) the start-up of operations at the DBM water systems during the second quarter of 2017. These increases were partially offset by decreases from (i) the Property Exchange in March 2017, (ii) lower throughput at the Springfield and Marcellus Interest systems, (iii) the partial equity treatment of the above-market swap agreement at the MGR assets beginning January 1, 2017, and (iv) the sale of the Hugoton system in October 2016.

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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 and produced water assets. Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.15 and $0.10 for the three and nine months ended September 30, 2017, respectively, primarily due to the Property Exchange in March 2017 and increased throughput at the DBM complex. Adjusted gross margin per Bbl for crude, NGL and produced water assets decreased by $0.17 for the three months ended September 30, 2017, primarily due to (i) lower throughput at the Springfield oil gathering system, (ii) lower distributions received from the Mont Belvieu JV and (iii) the start-up of operations at the DBM water systems during the second quarter of 2017. Adjusted gross margin per Bbl for crude, NGL and produced water assets decreased by $0.05 for the nine months ended September 30, 2017, primarily due to (i) lower throughput at the Springfield oil gathering system and (ii) the start-up of operations at the DBM water systems during the second quarter of 2017. These decreases were partially offset during the three and nine months ended September 30, 2017, by higher distributions received from TEP.

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 investments, 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 decreased by $20.3 million for the three months ended September 30, 2017, primarily due to a $93.6 million increase in cost of product (net of lower of cost or market inventory adjustments), a $13.7 million decrease in business interruption proceeds, a $4.8 million increase in operation and maintenance expenses, and a $1.7 million increase in net income attributable to noncontrolling interest. These amounts were partially offset by a $93.1 million increase in total revenues and other and a $2.0 million increase in distributions from equity investments. Adjusted EBITDA increased by $27.8 million for the nine months ended September 30, 2017, primarily due to a $322.9 million increase in total revenues and other, a $13.6 million increase in business interruption proceeds and a $4.3 million increase in distributions from equity investments. These amounts were partially offset by a $304.8 million increase in cost of product (net of lower of cost or market inventory adjustments), a $3.3 million increase in operation and maintenance expenses, a $2.4 million increase in general and administrative expenses excluding non-cash equity-based compensation expense, and a $2.3 million increase in property and other tax expense.

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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, it is not a reflection of our ability to generate cash from operations.

Distributable cash flow decreased by $5.5 million for the three months ended September 30, 2017, primarily due to a $20.3 million decrease in Adjusted EBITDA and a $4.4 million increase in net cash paid for interest expense. These amounts were partially offset by a $14.9 million decrease in Series A Preferred unit distributions and a $4.7 million decrease in cash paid for maintenance capital expenditures.

Distributable cash flow increased by $67.0 million for the nine months ended September 30, 2017, primarily due to a $27.8 million increase in Adjusted EBITDA, a $23.4 million decrease in Series A Preferred unit distributions, a $22.2 million decrease in cash paid for maintenance capital expenditures and an $11.9 million increase in the above-market component of the swap agreements with Anadarko. These amounts were partially offset by an $18.3 million increase in net cash paid for interest expense.

Reconciliation of non-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) attributable to Western Gas Partners, LP 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.

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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) attributable to Western Gas Partners, LP and net cash provided by operating activities, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2017	2016	2017	2016
Reconciliation of Operating income (loss) to Adjusted gross margin attributable to Western Gas Partners, LP				
Operating income (loss)	$179,456	$197,288	$525,456	$527,053
Add:				
Distributions from equity investments	29,145	27,133	80,568	76,263
Operation and maintenance	79,536	74,755	229,444	226,141
General and administrative	12,158	11,382	35,402	33,542
Property and other taxes	11,215	10,670	35,433	33,098
Depreciation and amortization	72,539	67,246	216,272	199,646
Impairments	2,159	2,392	170,079	11,313
Less:				
Gain (loss) on divestiture and other, net	72	(6,230)	135,017	(8,769)
Proceeds from business interruption insurance claims	—	13,667	29,882	16,270
Equity income, net – affiliates	21,519	20,294	62,708	56,801
Reimbursed electricity-related charges recorded as revenues	14,323	15,170	42,338	45,707
Adjusted gross margin attributable to noncontrolling interest	5,878	3,984	13,189	12,588
Adjusted gross margin attributable to Western Gas Partners, LP	$344,416	$343,981	$1,009,520	$984,459
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$305,337	$306,393	$904,620	$877,583
Adjusted gross margin for crude, NGL and produced water assets	39,079	37,588	104,900	106,876

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thousands	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Adjusted EBITDA attributable to Western Gas Partners, LP				
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Add:				
Distributions from equity investments	29,145	27,133	80,568	76,263
Non-cash equity-based compensation expense	1,258	1,469	3,479	4,018
Interest expense	35,544	30,768	106,794	75,687
Income tax expense	510	472	4,905	7,431
Depreciation and amortization (1)	71,812	66,589	214,213	197,678
Impairments	2,159	2,392	170,079	11,313
Other expense (1)	—	40	140	96
Less:				
Gain (loss) on divestiture and other, net	72	(6,230)	135,017	(8,769)
Equity income, net – affiliates	21,519	20,294	62,708	56,801
Interest income – affiliates	4,225	4,225	12,675	12,675
Other income (1)	283	150	960	272
Adjusted EBITDA attributable to Western Gas Partners, LP	$257,835	$278,170	$787,664	$759,834
Reconciliation of Net cash provided by operating activities to Adjusted EBITDA attributable to Western Gas Partners, LP				
Net cash provided by operating activities	$211,947	$263,872	$645,099	$657,738
Interest (income) expense, net	31,319	26,543	94,119	63,012
Uncontributed cash-based compensation awards	78	290	(94)	448
Accretion and amortization of long-term obligations, net	(1,055)	121	(3,194)	9,176
Current income tax (benefit) expense	395	131	1,023	5,110
Other (income) expense, net	(286)	(153)	(969)	(224)
Distributions from equity investments in excess of cumulative earnings – affiliates	7,034	5,981	16,255	16,592
Changes in operating working capital:				
Accounts receivable, net	56,335	7,866	46,972	41,108
Accounts and imbalance payables and accrued liabilities, net	(45,982)	(26,330)	(4,007)	(24,103)
Other	3,181	3,184	3,065	1,445
Adjusted EBITDA attributable to noncontrolling interest	(5,131)	(3,335)	(10,605)	(10,468)
Adjusted EBITDA attributable to Western Gas Partners, LP	$257,835	$278,170	$787,664	$759,834
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			$645,099	$657,738
Net cash used in investing activities			(514,797)	(1,040,692)
Net cash provided by (used in) financing activities			(335,792)	429,368

(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 September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Distributable cash flow and calculation of the Coverage ratio				
Net income (loss) attributable to Western Gas Partners, LP	$143,506	$167,746	$418,846	$448,327
Add:				
Distributions from equity investments	29,145	27,133	80,568	76,263
Non-cash equity-based compensation expense	1,258	1,469	3,479	4,018
Non-cash settled - interest expense, net [1]	—	(1,173)	71	(12,097)
Income tax (benefit) expense	510	472	4,905	7,431
Depreciation and amortization [2]	71,812	66,589	214,213	197,678
Impairments	2,159	2,392	170,079	11,313
Above-market component of swap agreements with Anadarko [3]	18,049	18,417	46,719	34,782
Other expense [2]	—	40	140	96
Less:				
Gain (loss) on divestiture and other, net	72	(6,230)	135,017	(8,769)
Equity income, net – affiliates	21,519	20,294	62,708	56,801
Cash paid for maintenance capital expenditures [2]	10,591	15,306	33,115	55,288
Capitalized interest	2,115	1,343	3,991	4,674
Cash paid for (reimbursement of) income taxes	—	—	189	67
Series A Preferred unit distributions	—	14,907	7,453	30,876
Other income [2]	283	150	960	272
Distributable cash flow	$231,859	$237,315	$695,587	$628,602
Distributions declared [4]				
Limited partners – common units	$138,105		$397,850	
General partner	73,933		210,432	
Total	$212,038		$608,282	
Coverage ratio	1.09 x		1.14 x	

(1) Includes amounts 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 $0.905 and $2.670 per unit declared for the three and nine months ended September 30, 2017, respectively.

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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 September 30, 2017, 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 our commodity price swap agreements, and will be determined by the Board of Directors 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.
During the second quarter of 2017, we reached a settlement with insurers related to the insurance claim filed for the incident at the DBM complex and final proceeds were received. Recoveries from the business interruption claim related to the DBM outage were recognized as income when cash proceeds were received from insurers. During the nine months ended September 30, 2017, we received $52.9 million in cash proceeds from insurers in final settlement of our claims related to the incident at the DBM complex, including $29.9 million for business interruption insurance claims and $23.0 million for 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).
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. The Board of Directors declared a cash distribution to our unitholders for the third quarter of 2017 of $0.905 per unit, or $212.0 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution is payable on November 13, 2017, to unitholders of record at the close of business on November 2, 2017. 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 March 1, 2020, 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 $11.7 million for the third quarter of 2017.
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.

Working capital. As of September 30, 2017, we had a $35.0 million working capital deficit, which we define as the amount by which current liabilities exceed current assets. Working capital is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. Our working capital deficit as of September 30, 2017, was primarily due to the costs incurred related to continued construction and expansion at the DBM and DJ Basin complexes and the DBJV system. As of September 30, 2017, we had $945.4 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.

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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 2017, the general partner’s Board of Directors has approved Estimated Maintenance Capital Expenditures (as defined in our partnership agreement) of $18.0 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:

	Nine Months Ended September 30,	
thousands	2017	2016
Acquisitions	$159,208	$716,465
Expansion capital expenditures	$384,416	$312,505
Maintenance capital expenditures	33,391	55,293
Total capital expenditures (1) (2)	$417,807	$367,798
Capital incurred (2)	$504,286	$355,674

(1) Capital expenditures for the nine months ended September 30, 2017 and 2016, are presented net of $1.4 million and $4.9 million, respectively, of contributions in aid of construction costs from affiliates.

(2) For the nine months ended September 30, 2017 and 2016, included $4.0 million and $4.7 million, respectively, of capitalized interest.

Acquisitions during 2017 included the Additional DBJV System Interest and equipment purchases from Anadarko. Acquisitions during 2016 included Springfield and equipment purchases from Anadarko. 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, increased by $50.0 million for the nine months ended September 30, 2017. Expansion capital expenditures increased by $71.9 million (including a $0.7 million decrease in capitalized interest) for the nine months ended September 30, 2017, primarily due to an increase of (i) $70.4 million at the DBJV system and $23.7 million at the DJ Basin complex, both due to pipe and compression projects and (ii) an increase of $50.9 million due to the construction of the DBM water system. These increases were partially offset by decreases of $60.3 million at the DBM complex and $9.9 million at the Haley system. Maintenance capital expenditures decreased by $21.9 million for the nine months ended September 30, 2017, primarily at the DBM complex due to repairs made in 2016 as a result of the DBM outage and at the Non-Operated Marcellus Interest systems due to the Property Exchange in March 2017.

We have updated our estimated total capital expenditures for the year ending December 31, 2017, (including our 75% share of Chipeta's capital expenditures and excluding acquisitions) from an originally reported $900.0 million to $1.0 billion, to a current range of $800.0 million to $850.0 million. We have also updated our estimated maintenance capital expenditures from an originally reported $60.0 million to $80.0 million, to a current range of $50.0 million to $55.0 million. Based on the midpoint of the ranges, the total capital expenditure and maintenance capital expenditure estimates represent decreases of 13% and 25%, respectively, from the initial 2017 estimates due to increased capital efficiency and shifting capital spending into later periods.

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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:

	Nine Months Ended September 30,	
thousands	2017	2016
Net cash provided by (used in):		
Operating activities	$645,099	$657,738
Investing activities	(514,797)	(1,040,692)
Financing activities	(335,792)	429,368
Net increase (decrease) in cash and cash equivalents	$(205,490)	$46,414

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2017, decreased primarily due to the impact of changes in working capital items. Also, for a discussion of our results of operations as compared to the prior period, refer to Operating Results within this Item 2.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2017, included the following:

- $417.8 million of capital expenditures, net of $1.4 million of contributions in aid of construction costs from affiliates, primarily related to construction and expansion at the DBM and DJ Basin complexes and the DBJV system;
- $155.3 million of cash consideration paid as part of the Property Exchange;
- $3.9 million of cash paid for equipment purchases from Anadarko;
- $23.3 million of net proceeds from the sale of the Helper and Clawson systems in Utah;
- $23.0 million of proceeds from property insurance claims attributable to the DBM outage; and
- $16.3 million of distributions from equity investments in excess of cumulative earnings.

Net cash used in investing activities for the nine months ended September 30, 2016, included the following:

- $712.5 million of cash paid for the acquisition of Springfield;
- $367.8 million of capital expenditures, net of $4.9 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;
- $4.0 million of cash paid for equipment purchases from Anadarko;
- $16.6 million of distributions from equity investments in excess of cumulative earnings; and
- $18.4 million of proceeds from property insurance claims attributable to the DBM outage.

Financing Activities. Net cash used in financing activities for the nine months ended September 30, 2017, included the following:

- $589.3 million of distributions paid to our unitholders;

- $37.3 million of cash paid to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko;
- $9.0 million of distributions paid to the noncontrolling interest owner of Chipeta;

- $250.0 million of borrowings under our RCF, which were used for general partnership purposes; and

- $46.7 million of capital contribution from Anadarko related to the above-market component of swap agreements.

Net cash provided by financing activities for the nine months ended September 30, 2016, included the following:

- $880.0 million of repayments of outstanding borrowings under our RCF;

- $490.3 million of distributions paid to our unitholders;

- $29.3 million of net distributions paid to Anadarko representing pre-acquisition intercompany transactions attributable to Springfield;

- $11.3 million of distributions paid to the noncontrolling interest owner of Chipeta;

- $600.0 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;

- $494.6 million of net proceeds from the 2026 Notes offering in July 2016, 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;

- $440.0 million of net proceeds from the issuance of 14,030,611 Series A Preferred units in March 2016, all of which was used to fund a portion of the acquisition of Springfield;

- $246.9 million of net proceeds from the issuance of 7,892,220 Series A Preferred units in April 2016, all of which was used to pay down amounts borrowed under our RCF in connection with the acquisition of Springfield;

- $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; and

- $34.8 million of capital contribution from Anadarko related to the above-market component of swap agreements.

Debt and credit facility. At September 30, 2017, 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, $600.0 million aggregate principal amount of the 2044 Notes, $500.0 million aggregate principal amount of the 2025 Notes, $500.0 million aggregate principal amount of the 2026 Notes and $250.0 million of borrowings outstanding under our RCF. As of September 30, 2017, the carrying value of our outstanding debt was $3.3 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. The 2018 Notes, which are due in August 2018, were classified as long-term debt on the consolidated balance sheet at September 30, 2017, as we have the ability and intent to refinance these obligations using long-term debt. At September 30, 2017, we were in compliance with all covenants under the indentures governing our outstanding notes.

Revolving credit facility. As of September 30, 2017, we had $250.0 million of outstanding RCF borrowings and $4.6 million in outstanding letters of credit, resulting in $945.4 million available for borrowing under the RCF, which matures in February 2020. At September 30, 2017, the interest rate on the RCF was 2.54%, the facility fee rate was 0.20% and we were in compliance with all covenants under the RCF.

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Deferred purchase price obligation - Anadarko. Prior to our agreement with Anadarko to settle our deferred purchase price obligation early, the consideration that would have been paid for the March 2015 acquisition of DBJV from Anadarko, consisted of a cash payment to Anadarko due on March 31, 2020. The cash payment would have been 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 was defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. In May 2017, we reached an agreement with Anadarko to settle this obligation whereby we made a cash payment to Anadarko of $37.3 million, equal to the estimated net present value of the obligation at March 31, 2017. 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 statement on file with the SEC. We may also 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. We have an effective registration statement with the SEC relating to the public resale of the common units issued 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.

We are dependent upon a single producer, Anadarko, for a substantial portion 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 September 30, 2017, including, but not limited to, increases in committed capital.

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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.

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, and 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 commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, we currently have in place commodity price swap agreements with Anadarko covering activity at the DJ Basin complex and the MGR assets. On December 1, 2016, we renewed these commodity price swap agreements through December 31, 2017, with an effective date of January 1, 2017. 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 that a 10% increase or decrease in commodity 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 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. In June 2017, the Federal Open Market Committee raised the target range for the federal funds rate from 3/4 to one percent to one to 1 1/4 percent. This increase, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. As of September 30, 2017, we had $250.0 million of outstanding borrowings under the RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). 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 September 30, 2017.

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 concluded that the Partnership's disclosure controls and procedures were effective as of September 30, 2017.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended September 30, 2017, that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Kerr-McGee Gathering LLC ("KMGG"), a wholly owned subsidiary of the Partnership, is currently in negotiations with the U.S. Environmental Protection Agency (the "EPA") and the Department of Justice with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act at its Fort Lupton facility in the DJ Basin complex.

Also, WGR Operating, LP, another wholly owned subsidiary of the Partnership, is currently in negotiations with the EPA 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 in these matters, management believes that it is reasonably likely a resolution of these matters will result in a fine or penalty for each matter 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.

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Item 1A. Risk Factors

Security holders and potential investors in our securities should carefully consider the risk factors set forth under Part I, Item 1A in our Form 10-K for the year ended December 31, 2016, 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, 2016, 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.

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

Series A Preferred units. In connection with the early conversion of the Series A Preferred units into common units on a one-for-one basis on March 1, 2017, and May 2, 2017, we issued 10,961,415 and 10,961,416 common units, respectively, in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof.

PIK Class C units. During the nine months ended September 30, 2017, in connection with the quarterly distribution for the Class C units, we issued the following additional Class C units ("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
2016			
December 31	178,977	$10,719	February 2017
2017			
March 31	206,218	$12,355	May 2017
June 30	234,315	13,206	August 2017

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. All outstanding Class C units will convert into common units on a one-for-one basis on March 1, 2020, unless we elect 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).

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Exhibit Number	Description
2.12#	Amendment No. 1 to Purchase and Sale Agreement, dated as of May 22, 2017, by and between WGR Asset Holding Company LLC and Delaware Basin Midstream, LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 23, 2017, File No. 001-34046).
2.13#	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).
2.14#	Interest Swap and Purchase Agreement, dated February 9, 2017, among Western Gas Partners, LP, WGR Operating, LP, Delaware Basin JV Gathering, LLC, Williams Partners L.P., Williams Midstream Gas Services LLC and Appalachia Midstream Services, L.L.C. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 9, 2017, File No. 001-34046).
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	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	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated February 22, 2017 (incorporated by reference to Exhibit 3.4 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
3.5	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).
3.6	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 4.3 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).

Exhibit Number	Description
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 4.4 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	Eighth Supplemental Indenture, dated as of July 12, 2016, 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 July 12, 2016, File No. 001-34046).
4.14	Form of 4.650% Senior Notes due 2026 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 12, 2016, File No. 001-34046).
4.15	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).
4.16	Consent and Conversion Agreement, dated as of February 22, 2017, by and among the Partnership and the holders of the outstanding Series A Preferred Units party thereto (incorporated by reference to Exhibit 4.16 to Western Gas Partners, LP's Annual Report on Form 10-K filed on February 23, 2017, File No. 001-34046).
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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 hereunto duly authorized.

WESTERN GAS PARTNERS, LP

November 1, 2017

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

November 1, 2017

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