Western Gas Partners LP
Form 10-Q
October 31, 2018

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, 2018

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 every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes þ No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 ¨

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 152,609,285 common units outstanding as of October 29, 2018.

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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: Our 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, FRP, Whitethorn and Cactus II.

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: 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.

Cactus II: Cactus II Pipeline LLC.

Chipeta: Chipeta Processing, LLC.

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

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 gathering and 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 Key Performance Metrics under Part I, Item 2 of this Form 10-Q.

Exchange Act: The Securities Exchange Act of 1934, as amended.

Fort Union: Fort Union Gas Gathering, LLC.

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.

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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.
MBbls/d: 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: Million British thermal units.
MMcf: Million cubic feet.
MMcf/d: 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: Our 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 $1.5 billion senior unsecured revolving credit facility.
Red Desert complex: The Patrick Draw processing plant, the Red Desert processing plant, associated gathering lines, and related facilities.
Rendezvous: Rendezvous Gas Services, LLC.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
SEC: U.S. Securities and Exchange Commission.
Springfield gas gathering system: A gas gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.

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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.
Whitethorn LLC: Whitethorn Pipeline Company LLC.
$500.0 million COP: The continuous offering program that may be undertaken pursuant to the registration statement filed with the SEC in July 2017 for 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	2018	2017	2018	2017
Revenues and other – affiliates				
Service revenues – fee based	$204,090	$157,303	$582,579	$484,601
Service revenues – product based	701	—	1,228	—
Product sales	69,723	185,002	182,372	489,172
Other	—	8,822	—	8,822
Total revenues and other – affiliates	274,514	351,127	766,179	982,595
Revenues and other – third parties				
Service revenues – fee based	205,016	148,884	563,520	428,835
Service revenues – product based	22,034	—	66,205	—
Product sales	5,427	74,139	35,366	201,318
Other	771	545	1,213	3,590
Total revenues and other – third parties	233,248	223,568	666,304	633,743
Total revenues and other	507,762	574,695	1,432,483	1,616,338
Equity income, net – affiliates	43,110	21,519	102,752	62,708
Operating expenses				
Cost of product (1)	105,966	239,223	303,518	631,859
Operation and maintenance (1)	111,359	79,536	300,266	229,444
General and administrative (1)	14,467	12,158	42,634	35,402
Property and other taxes	10,954	11,215	35,090	35,433
Depreciation and amortization	82,553	72,539	238,187	216,272
Impairments	25,317	2,159	152,708	170,079
Total operating expenses	350,616	416,830	1,072,403	1,318,489
Gain (loss) on divestiture and other, net (2)	65	72	351	135,017
Proceeds from business interruption insurance claims	—	—	—	29,882
Operating income (loss)	200,321	179,456	463,183	525,456
Interest income – affiliates	4,225	4,225	12,675	12,675
Interest expense	(47,991)	(35,544)	(131,663)	(106,794)
Other income (expense), net	598	286	2,609	969
Income (loss) before income taxes	157,153	148,423	346,804	432,306
Income tax (benefit) expense	1,517	510	3,301	4,905
Net income (loss)	155,636	147,913	343,503	427,401
Net income attributable to noncontrolling interest	990	4,407	6,786	8,555
Net income (loss) attributable to Western Gas Partners, LP	$154,646	$143,506	$336,717	$418,846
Limited partners’ interest in net income (loss):				
Net income (loss) attributable to Western Gas Partners, LP	$154,646	$143,506	$336,717	$418,846
Series A Preferred units interest in net (income) loss (3)	—	—	—	(42,373)
General partner interest in net (income) loss (3)	(88,551)	(78,376)	(256,166)	(222,903)
Common and Class C limited partners’ interest in net income (loss) (3)	66,095	65,130	80,551	153,570
Net income (loss) per common unit – basic and diluted (3)	$0.39	$0.38	$0.46	$0.91

(1) Cost of product includes product purchases from affiliates (as defined in Note 1) of $47.0 million and $131.4 million for the three and nine months ended September 30, 2018, respectively, and $22.9 million and $60.5 million for the three and nine months ended September 30, 2017, respectively. Operation and maintenance includes charges from affiliates of $25.1 million and $68.8 million for the three and nine months ended September 30, 2018, respectively, and $18.1 million and $53.7 million for the three and nine months ended September 30, 2017, respectively. General and administrative includes charges from affiliates of $11.6 million and $34.4 million for the three and nine months ended September 30, 2018, respectively, and $10.1 million and $29.0 million for the three and nine months ended September 30, 2017, respectively. See Note 6.

(2) Includes losses related to an incident at the DBM complex for the nine months ended September 30, 2017. See Note 1.

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

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$130,668	$78,814
Accounts receivable, net [(1)]	224,986	160,432
Other current assets [(2)]	25,970	14,816
Total current assets	381,624	254,062
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	8,912,755	7,864,535
Less accumulated depreciation	2,494,121	2,133,644
Net property, plant and equipment	6,418,634	5,730,891
Goodwill	416,160	416,160
Other intangible assets	753,947	775,269
Equity investments	786,876	566,211
Other assets	14,057	11,757
Total assets	$9,031,298	$8,014,350
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables	$360,651	$349,801
Accrued ad valorem taxes	37,123	26,633
Accrued liabilities [(3)]	114,286	47,899
Total current liabilities	512,060	424,333
Long-term liabilities		
Long-term debt	4,566,464	3,464,712
Deferred income taxes	10,285	7,409
Asset retirement obligations	157,933	143,394
Other liabilities [(4)]	141,957	3,491
Total long-term liabilities	4,876,639	3,619,006
Total liabilities	5,388,699	4,043,339
Equity and partners' capital		
Common units (152,609,285 and 152,602,105 units issued and outstanding at September 30, 2018, and December 31, 2017, respectively)	2,595,719	2,950,010
Class C units (14,045,429 and 13,243,883 units issued and outstanding at September 30, 2018, and December 31, 2017, respectively) [(5)]	787,420	780,040
General partner units (2,583,068 units issued and outstanding at September 30, 2018, and December 31, 2017)	199,433	179,232
Total partners' capital	3,582,572	3,909,282
Noncontrolling interest	60,027	61,729
Total equity and partners' capital	3,642,599	3,971,011
Total liabilities, equity and partners' capital	$9,031,298	$8,014,350

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $59.2 million and $36.3 million as of September 30, 2018, and December 31, 2017, respectively.

(2) Other current assets includes affiliate amounts of $1.4 million and zero as of September 30, 2018, and December 31, 2017, respectively.

(3) Accrued liabilities includes affiliate amounts of $2.3 million and $0.2 million as of September 30, 2018, and December 31, 2017, respectively.

(4) Other liabilities includes affiliate amounts of $50.2 million and $0.7 million as of September 30, 2018, and December 31, 2017, respectively.

(5) 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 5.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENT OF EQUITY AND PARTNERS' CAPITAL
(UNAUDITED)

	Partners' Capital				
thousands	Common Units	Class C Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2017	$2,950,010	$780,040	$179,232	$ 61,729	$3,971,011
Cumulative effect of accounting change [1]	(41,108)	(3,533)	(696)	958	(44,379)
Net income (loss)	72,072	8,479	256,166	6,786	343,503
Above-market component of swap agreements with Anadarko [2]	40,722	—	—	—	40,722
Amortization of beneficial conversion feature of Class C units	(2,434)	2,434	—	—	—
Distributions to noncontrolling interest owner	—	—	—	(9,446)	(9,446)
Distributions to unitholders	(428,056)	—	(235,354)	—	(663,410)
Contributions of equity-based compensation from Anadarko	4,210	—	85	—	4,295
Other	303	—	—	—	303
Balance at September 30, 2018	$2,595,719	$787,420	$199,433	$ 60,027	$3,642,599

(1) See Note 1.
(2) See Note 6.

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	2018	2017
Cash flows from operating activities		
Net income (loss)	$343,503	$427,401
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	238,187	216,272
Impairments	152,708	170,079
Non-cash equity-based compensation expense	4,620	3,573
Deferred income taxes	3,054	3,882
Accretion and amortization of long-term obligations, net	3,883	3,194
Equity income, net – affiliates	(102,752)	(62,708)
Distributions from equity investment earnings – affiliates	93,827	64,313
(Gain) loss on divestiture and other, net [1]	(351)	(135,017)
Lower of cost or market inventory adjustments	184	140
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	(64,544)	(46,972)
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	55,354	4,007
Change in other items, net	24,049	(3,065)
Net cash provided by operating activities	751,722	645,099
Cash flows from investing activities		
Capital expenditures	(949,022)	(419,193)
Contributions in aid of construction costs from affiliates	—	1,386
Acquisitions from affiliates	(254)	(3,910)
Acquisitions from third parties	(161,858)	(155,298)
Investments in equity affiliates	(67,979)	(384)
Distributions from equity investments in excess of cumulative earnings – affiliates	18,097	16,255
Proceeds from the sale of assets to third parties	332	23,370
Proceeds from property insurance claims	—	22,977
Net cash used in investing activities	(1,160,684)	(514,797)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	2,135,637	249,989
Repayments of debt	(1,040,000)	—
Settlement of the Deferred purchase price obligation – Anadarko [2]	—	(37,346)
Increase (decrease) in outstanding checks	(2,687)	3,310
Proceeds from the issuance of common units, net of offering expenses	—	(183)
Distributions to unitholders [3]	(663,410)	(589,262)
Distributions to noncontrolling interest owner	(9,446)	(9,049)
Net contributions from (distributions to) Anadarko	—	30
Above-market component of swap agreements with Anadarko [3]	40,722	46,719
Net cash provided by (used in) financing activities	460,816	(335,792)
Net increase (decrease) in cash and cash equivalents	51,854	(205,490)
Cash and cash equivalents at beginning of period	78,814	357,925
Cash and cash equivalents at end of period	$130,668	$152,435
Supplemental disclosures		
Accretion expense and revisions to the Deferred purchase price obligation – Anadarko	$—	$(4,094)

Net distributions to (contributions from) Anadarko of other assets	—	(1,373)
Interest paid, net of capitalized interest	113,866	97,811
Taxes paid (reimbursements received)	(87)	189
Accrued capital expenditures	178,694	165,732
Fair value of properties and equipment from non-cash third party transactions [2]	—	551,453

(1) Includes losses related to an incident at the DBM complex for the nine months ended September 30, 2017. See Note 1.

(2) See Note 3.

(3) See Note 6.

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 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 5). 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"), Front Range Pipeline LLC ("FRP"), Whitethorn Pipeline Company LLC ("Whitethorn LLC") and Cactus II Pipeline LLC ("Cactus II"). See Note 3. 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. In addition, in its capacity as a processor of natural gas, the Partnership also buys and sells natural gas, NGLs and condensate on behalf of itself and as agent for its customers under certain of its contracts. The Partnership provides these midstream services for Anadarko, as well as for third-party producers and customers.
As of September 30, 2018, the Partnership's assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	3	3	2
Treating facilities	19	3	—	3
Natural gas processing plants/trains	20	4	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	2

(1) Includes the DBM water systems.

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania, Texas and New Mexico. Mentone Train I, a processing train that is part of the DBM complex, is expected to commence operation in the fourth quarter of 2018.

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

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

Basis of presentation. The following table outlines the Partnership's ownership interests and the accounting method of consolidation used in the Partnership's consolidated financial statements for entities not wholly owned:

	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	%
Whitethorn	20	%
Cactus II	15	%
Proportionate consolidation [2]		
Marcellus Interest systems	33.75	%
Newcastle system	50	%
Springfield system	50.1	%
Full consolidation		
Chipeta [3]	75	%

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

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

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

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

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 2017 Form 10-K, as filed with the SEC on February 16, 2018. Management believes that the disclosures made are adequate to make the information not misleading.

Adjustments to previously issued financial statements. The Partnership's unaudited consolidated statements of operations for the nine months ended September 30, 2018, include adjustments to revenue and cost of product expense of the following amounts: (i) $39.0 million increase in Service revenues - fee based, (ii) $12.6 million increase in Product sales and (iii) $51.6 million increase in Cost of product; all of which relate to the six months ended June 30, 2018. During the third quarter of 2018, management determined that under ASU 2014-09, Revenue from Contracts with Customers (Topic 606) (“Topic 606”) adopted on January 1, 2018, the Partnership’s marketing affiliate was acting as the Partnership’s agent in certain product sales transactions on behalf of the Partnership and in performing marketing services on behalf of the Partnership’s customers. The adjustments have no impact to Operating income (loss), Net income (loss), the balance sheets, cash flows or any non-GAAP metric the Partnership uses to evaluate its operations (see Key Performance Metrics under Item 2 of this Form 10-Q) and are not considered material to the Partnership’s results of operations for the nine months ended September 30, 2018. The Partnership will revise its previously reported unaudited financial statements for 2018 interim periods to reflect the adjustments in future filings.

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

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

Presentation of Partnership assets. The term “Partnership assets” includes both the assets owned and the interests accounted for under the equity method by the Partnership as of September 30, 2018 (see Note 8). Because Anadarko controls the Partnership through its 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.
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 included 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.

Shutdown of gathering systems. In May 2018, after assessing a number of factors, with safety and protection of the environment as the primary focus, the Partnership decided to take the Kitty Draw gathering system in Wyoming (part of the Hilight system) and the Third Creek gathering system in Colorado (part of the DJ Basin complex) permanently out of service. Results for the three and nine months ended September 30, 2018, reflect (i) accruals of zero and $10.9 million, respectively, in anticipated costs associated with the shutdown of the systems, recorded as a reduction in affiliate Product sales in the consolidated statements of operations and (ii) impairment expense of $6.8 million and $134.0 million, respectively, associated with reducing the net book value of the gathering systems and increasing the asset retirement obligation.

Insurance recoveries. In December 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. During the nine months ended September 30, 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. During the nine months ended September 30, 2017, the Partnership received $52.9 million in cash proceeds from insurers, including $29.9 million in proceeds from business interruption insurance claims and $23.0 million in proceeds from property insurance claims.

Recently adopted accounting standards. Accounting Standards Update (“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. The Partnership adopted this ASU using a retrospective approach on January 1, 2018, and the adoption did not impact the consolidated financial statements.

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

Revenue from contracts with customers (Topic 606). The Partnership adopted Topic 606 on January 1, 2018, using the modified retrospective method applied to contracts that were not completed as of January 1, 2018. The cumulative effect adjustment that was recognized in the opening balance of equity and partners' capital was a decrease of $44.4 million. The comparative historical financial information has not been adjusted and continues to be reported under Revenue Recognition (Topic 605) ("Topic 605").

Effective January 1, 2018, the Partnership changed its accounting policy for revenue recognition as detailed below:

- Fee-based gathering / processing. Under Topic 605, fee revenues were recognized based on the rate in effect for the month of service, even when certain fees were charged on an upfront or limited-term basis. In addition, deficiency fees were charged and recognized only when the customer did not meet the specified delivery minimums for the completed performance period. Under Topic 606, (i) revenues continue to be recognized based on the rate in effect when the fee is either the same rate per unit over the contract term or when the fee escalates and the escalation factor approximates inflation, (ii) deficiency fees are estimated and recognized during the performance period as the services are performed for the customer's delivered volumes, and (iii) timing differences between Service revenues – fee based recognized and amounts billed to customers are recognized as contract assets or contract liabilities, as appropriate, which results in a change in the timing of revenue and changes to net income as a result of the revenue contract's consideration provisions. In addition, under Topic 606, revenue associated with upfront or limited-term fees is recognized over the expected period of customer benefit, which is generally the life of the related properties. These revenues also include revenues earned for marketing services performed on behalf of the Partnership's customers, and the expense associated with these marketing activities is recognized in cost of product expense, resulting in no impact to operating income.

- Cost of service rate adjustments. Under Topic 605, revenue was recognized based on the amounts billed to customers each period as Service revenues – fee based. Under Topic 606, fixed minimum volume commitment demand fees and variable fees that are also billed on these minimum volumes are recognized as Service revenues – fee based on a consistent per-unit rate over the term of the contract. Annual adjustments are made to the cost of service rates charged to customers, and, as a result, a cumulative catch-up revenue adjustment related to the services already provided under the contract may be recorded in future periods, with revenues for the remaining term of the contract recognized on a consistent per-unit rate. Fees received on volumes in excess of the minimum volumes are recognized as Service revenues – fee based as service is provided to the customer based on the billing rate in effect for the performance period. This revenue recognition timing does not affect billings to customers, and differences between amounts billed and revenue recognized are recorded as contract assets or liabilities, as appropriate.

- Aid in construction. Under Topic 605, aid in construction reimbursements were reflected as a reduction to property, plant and equipment upon receipt (and a reduction to capital expenditures). Under Topic 606, reimbursement of capital costs received from customers is reflected as a contract liability (deferred revenue) upon receipt. The contract liability is amortized to Service revenues – fee based over the expected period of customer benefit, which is generally the life of the related properties.

- Percent-of-proceeds gathering / processing. Under Topic 605, the Partnership recognized cost of product expense when the product was purchased from a producer to whom it provides services, and the Partnership recognized revenue when the product was sold to Anadarko or a third party. Under Topic 606, in some instances, where all or a percentage of the proceeds from the sale must be returned to the producer, the net margin from the purchase and sale transactions is presented net within Service revenues – product based because the Partnership is acting as the producer's agent in the product sale.

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

- Noncash consideration - keep-whole and percent-of-product agreements. Under Topic 605, the Partnership recognized revenues only upon the sale of the related products. Under Topic 606, (i) Service revenues – product based is recognized for the products received as noncash consideration in exchange for the services provided, with the keep-whole noncash consideration value based on the net value of the NGLs over the replacement residue gas cost, and (ii) product sales revenue is recognized, along with cost of product expense related to the sale, when the product is sold to Anadarko or a third party. When the product is sold to Anadarko, Anadarko is acting as the Partnership's agent in the product sale and the Partnership recognizes revenue, along with cost of product expense related to the sale, based on the Anadarko sales price to the third party, resulting in no impact to operating income.

- Wellhead purchase / sale incorporated into gathering / processing. Under Topic 605, the natural gas purchase cost was recognized as cost of product expense and any specified gathering or processing fees charged to the producer were recognized as revenues. Under Topic 606, the fees charged to the producer under this contract type are recognized as adjustments to the amount recognized in cost of product expense instead of revenues when such fees relate to services performed after control of the product transfers to the Partnership.

The following tables summarize the impact of adopting Topic 606 on the impacted line items within the consolidated statements of operations and the consolidated balance sheet. The differences between revenue as reported following Topic 606 and revenue as it would have been reported under Topic 605 are due to the changes described above.

	Three Months Ended September 30, 2018		
thousands	As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$409,106	$396,161	$ 12,945
Service revenues – product based	22,735	—	22,735
Product sales	75,150	366,603	(291,453)
Expenses			
Cost of product	105,966	353,641	(247,675)
Operation and maintenance	111,359	111,327	32
Depreciation and amortization	82,553	81,824	729
Income tax (benefit) expense	1,517	1,580	(63)
Net income attributable to noncontrolling interest	990	3,166	(2,176)
Net income (loss) attributable to Western Gas Partners, LP	154,646	161,266	(6,620)

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

thousands	Nine Months Ended September 30, 2018 As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$ 1,146,099	$ 1,096,708	$ 49,391
Service revenues – product based	67,433	—	67,433
Product sales	217,738	978,127	(760,389)
Expenses			
Cost of product	303,518	940,936	(637,418)
Operation and maintenance	300,266	300,098	168
Depreciation and amortization	238,187	236,102	2,085
Impairments	152,708	152,663	45
Income tax (benefit) expense	3,301	3,361	(60)
Net income attributable to noncontrolling interest	6,786	7,718	(932)
Net income (loss) attributable to Western Gas Partners, LP	336,717	344,170	(7,453)

thousands	September 30, 2018 As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Assets			
Other current assets	$ 25,970	$ 23,222	$ 2,748
Net property, plant and equipment	6,418,634	6,320,225	98,409
Other assets	14,057	13,894	163
Liabilities			
Accrued liabilities	114,286	106,592	7,694
Deferred income taxes	10,285	10,519	(234)
Other liabilities	141,957	2,781	139,176
Equity and partners' capital			
Total equity and partners' capital	3,642,599	3,687,915	(45,316)

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

New accounting standards issued but not yet adopted. ASU 2016-02, Leases (Topic 842) requires lessees to recognize a lease liability and a right-of-use ("ROU") asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. This ASU modifies the definition of a lease and outlines the recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. The Partnership plans to make certain elections allowing the Partnership not to reassess contracts that commenced prior to adoption, to continue applying its current accounting policy for existing or expired land easements and not to recognize ROU assets or lease liabilities for short-term leases. The Partnership continues to review contracts in its portfolio of leased assets to assess the impact of adopting this ASU, which is expected to primarily impact other assets and other long-term liabilities. To facilitate compliance with this ASU, the Partnership expects to implement new accounting software and complete the evaluation of its systems, processes and internal controls by the end of 2018. The Partnership will adopt this ASU on January 1, 2019, using a modified retrospective approach. As permitted by ASU 2018-11, Leases (Topic 842): Targeted Improvements, the Partnership does not expect to adjust comparative period financial statements.

Revenue and cost of product. Upon adoption of the new revenue recognition standard on January 1, 2018 (discussed in Recently adopted accounting standards), the Partnership changed its accounting policy for revenue recognition as described below.

The Partnership provides gathering, processing, treating, transportation and disposal services pursuant to a variety of contracts. Under these arrangements, the Partnership receives fees and/or retains a percentage of products or a percentage of the proceeds from the sale of the customer's products. These revenues are included in Service revenues and Product sales in the consolidated statements of operations. Payment is generally received from the customer in the month following the service or delivery of the product. Contracts with customers generally have initial terms ranging from 5 to 10 years.

Service revenues – fee based is recognized for fee-based contracts in the month of service based on the volumes delivered by the customer. Producers' wells or production facilities are connected to the Partnership's gathering systems for gathering, processing, treating, transportation and disposal of natural gas, NGLs, condensate, crude oil and produced water, as applicable. Revenues are valued based on the rate in effect for the month of service when the fee is either the same rate per unit over the contract term or when the fee escalates and the escalation factor approximates inflation. Deficiency fees charged to customers that do not meet their minimum delivery requirements are recognized as services are performed based on an estimate of the fees that will be billed upon completion of the performance period. Because of its significant upfront capital investment, the Partnership may charge additional service fees to customers for only a portion of the contract term (i.e., for the first year of a contract or until reaching a volume threshold), and these fees are recognized as revenue over the expected period of customer benefit, which is generally the life of the related properties. The Partnership also recognizes revenue and cost of product expense from marketing services performed on behalf of its customers by Anadarko.

The Partnership also receives Service revenues – fee based from contracts that have minimum volume commitment demand fees and fees that require periodic rate redeterminations based upon the related facility cost of service. These fees include fixed and variable consideration that are recognized on a consistent per-unit rate over the term of the contract. Annual adjustments are made to the cost of service rates charged to customers, and a cumulative catch-up revenue adjustment related to services already provided to the minimum volumes under the contract may be recorded in future periods, with revenues for the remaining term of the contract recognized on a consistent per-unit rate.

Service revenues – product based includes service revenues from percent-of-proceeds gathering and processing contracts that are recognized net of the cost of product for purchases from the Partnership's customers since it is acting as the agent in the product sale. Keep-whole and percent-of-product agreements result in Service revenues – product based being recognized when the natural gas and/or NGLs are received from the customer as noncash consideration for the services provided. Noncash consideration for these services is valued at the time the services are provided. Revenue from product sales is also recognized, along with the cost of product expense related to the sale, when the product received as noncash consideration is sold to either Anadarko or a third party. When the product is sold to Anadarko, Anadarko is acting as the Partnership's agent in the product sale, with the Partnership recognizing revenue and related cost of product expense associated with these marketing activities based on the Anadarko sales price to the third party.

WESTERN GAS PARTNERS, LP
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1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (CONTINUED)

The Partnership also purchases natural gas volumes from producers at the wellhead or from a production facility, typically at an index price, and charges the producer fees associated with the downstream gathering and processing services. When the fees relate to services performed after control of the product has transferred to the Partnership, the fees are treated as a reduction of the purchase cost. Revenue from product sales is recognized, along with cost of product expense related to the sale, when the purchased product is sold to either Anadarko or a third party.
The Partnership receives aid in construction reimbursements for certain capital costs necessary to provide services to customers (i.e., connection costs, etc.) under certain service contracts. Aid in construction reimbursements are reflected as a contract liability upon receipt and amortized to Service revenues – fee based over the expected period of customer benefit, which is generally the life of the related properties.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

The following table summarizes the Partnership's revenue from contracts with customers:

thousands	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018
Revenue from customers		
Service revenues – fee based	$409,106	$1,146,099
Service revenues – product based	22,735	67,433
Product sales	78,887	224,089
Total revenue from customers	510,728	1,437,621
Revenue from other than customers		
Net gains (losses) on commodity price swap agreements	(3,737)	(6,351)
Other	771	1,213
Total revenues and other	$507,762	$1,432,483

Contract balances. Receivables from customers, which are included in Accounts receivable, net on the consolidated balance sheets were $298.2 million and $244.4 million as of September 30, 2018, and December 31, 2017, respectively.
Contract assets primarily relate to accrued deficiency fees the Partnership expects to charge customers once the related performance periods are completed. The following table summarizes the current period activity related to contract assets from contracts with customers:

thousands	
Balance at December 31, 2017	$—
Cumulative effect of adopting Topic 606	5,129
Amounts transferred to Accounts receivable, net from contract assets recognized in the adoption effect [1]	(4,358)
Additional estimated revenues recognized [2]	2,140
Balance at September 30, 2018	$2,911

Contract assets at September 30, 2018	
Other current assets	$2,748

Other assets	163
Total contract assets from contracts with customers	$2,911

(1) Includes $(1.7) million for the three months ended September 30, 2018.
(2) Includes $(5.0) million for the three months ended September 30, 2018.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS (CONTINUED)

Contract liabilities primarily relate to (i) fees that are charged to customers for only a portion of the contract term and must be recognized as revenues over the expected period of customer benefit, (ii) fixed and variable fees under cost of service contracts that are received from customers for which revenue recognition is deferred and (iii) aid in construction payments received from customers that must be recognized over the expected period of customer benefit. The following table summarizes the current period activity related to contract liabilities from contracts with customers:

thousands	
Balance at December 31, 2017	$—
Cumulative effect of adopting Topic 606	120,717
Cash received or receivable, excluding revenues recognized during the period [1]	37,340
Revenues recognized during the period that were included in the adoption effect [2]	(10,850)
Balance at September 30, 2018	$147,207

Contract liabilities at September 30, 2018	
Accrued liabilities	$8,031
Other liabilities	139,176
Total contract liabilities from contracts with customers	$147,207

[1] Includes $(3.7) million for the three months ended September 30, 2018.
[2] Includes $(8.8) million for the three months ended September 30, 2018, of which $(7.5) million was from a performance obligation satisfied in a previous period related to the arbitration against SWEPI LP (see Note 11).

Transaction price allocated to remaining performance obligations. Revenues expected to be recognized from certain performance obligations that are unsatisfied (or partially unsatisfied) as of September 30, 2018, are reflected in the following table. The Partnership applies the optional exemptions in Topic 606 and does not disclose consideration for remaining performance obligations with an original expected duration of one year or less or for variable consideration related to unsatisfied (or partially unsatisfied) performance obligations. Therefore, the following table represents only a small portion of expected future revenues from existing contracts as most future revenues from customers are dependent on future variable customer volumes and in some cases variable commodity prices for those volumes.

thousands	
Remainder of 2018	$124,395
2019	480,211
2020	545,223
2021	524,810
2022	528,900
Thereafter	2,191,811
Total	$4,395,350

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3. ACQUISITIONS AND DIVESTITURES

Whitethorn LLC acquisition. In June 2018, the Partnership acquired a 20% interest in Whitethorn LLC, which owns a crude oil and condensate pipeline that originates in Midland, Texas and terminates in Sealy, Texas (the “Midland-to-Sealy pipeline”) and related storage facilities (collectively referred to as “Whitethorn”). A third party operates Whitethorn and oversees the related commercial activities. In connection with its investment in Whitethorn, the Partnership will share proportionally in the commercial activities. The Partnership acquired its 20% interest via a $150.6 million net investment, which was funded with cash on hand and is accounted for under the equity method. See Note 8.

Cactus II acquisition. In June 2018, the Partnership acquired a 15% interest in Cactus II, which will own a crude oil pipeline operated by a third party (the “Cactus II pipeline”) connecting West Texas to the Corpus Christi area. The Cactus II pipeline is under construction and expected to become operational in the fourth quarter of 2019. The Partnership acquired its 15% interest from a third party via an initial net investment of $11.3 million, which represented its share of costs incurred up to the date of acquisition. The initial investment was funded with cash on hand and the interest in Cactus II is accounted for under the equity method. See Note 8.

Property exchange. On March 17, 2017, the Partnership acquired an additional 50% interest in the Delaware Basin JV Gathering LLC (“DBJV”) system (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 was reflected as a nonmonetary transaction whereby the acquired Additional DBJV System Interest was 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 consolidated statements of operations beginning on the acquisition date in the first quarter of 2017.

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 DBJV from Anadarko consisted of a cash payment to Anadarko due on March 31, 2020. In May 2017, the Partnership reached an agreement with Anadarko to settle this obligation with a cash payment to Anadarko of $37.3 million, which was equal to the estimated net present value of the obligation at March 31, 2017.

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 $16.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

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4. 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
2017			
March 31	$ 0.875	$ 188,753	May 2017
June 30	0.890	207,491	August 2017
September 30	0.905	212,038	November 2017
December 31	0.920	216,586	February 2018
2018			
March 31	$ 0.935	$ 221,133	May 2018
June 30	0.950	225,691	August 2018
September 30 (1)	0.965	230,239	November 2018

(1) The Board of Directors declared a cash distribution to the Partnership's unitholders for the third quarter of 2018 of $0.965 per unit, or $230.2 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, 2018, to unitholders of record at the close of business on October 31, 2018.

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 into 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 5 for further discussion of the Class C units.

4. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

Series A Preferred unit distributions. As further described in Note 5, 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. 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, all 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. For the quarter ended March 31, 2017, the Series A Preferred unitholders received an aggregate cash distribution of $7.5 million (paid in May 2017).

General partner interest and incentive distribution rights. As of September 30, 2018, 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.

5. EQUITY AND PARTNERS’ CAPITAL

Equity offerings. In July 2017, the Partnership filed a registration statement with the SEC for the issuance of up to an aggregate of $500.0 million of common units pursuant to a new continuous offering program that has not yet been initiated.

Class C units. In November 2014, the Partnership issued 10,913,853 Class C units to APC 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 included in the calculation of earnings per unit.

Series A Preferred units. In 2016, the Partnership issued 21,922,831 Series A Preferred units to private investors. 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, representing a beneficial conversion feature at issuance. The impact of the beneficial conversion feature amortization was 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.

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 all remaining Series A Preferred units converted into common units on a one-for-one basis on May 2, 2017.

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5. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Partnership interests. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."
The following table summarizes the Partnership's units issued during the nine months ended September 30, 2018:

	Common Units	Class C Units	General Partner Units	Total
Balance at December 31, 2017	152,602,105	13,243,883	2,583,068	168,429,056
PIK Class C units	—	801,546	—	801,546
Long-Term Incentive Plan award vestings	7,180	—	—	7,180
Balance at September 30, 2018	152,609,285	14,045,429	2,583,068	169,237,782

Holdings of Partnership equity. As of September 30, 2018, WGP held 50,132,046 common units, representing a 29.6% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,583,068 general partner units, representing a 1.5% general partner interest in the Partnership, and 100% of the IDRs. As of September 30, 2018, (i) other subsidiaries of Anadarko collectively held 2,011,380 common units and 14,045,429 Class C units, representing an aggregate 9.5% limited partner interest in the Partnership and (ii) the public held 100,465,859 common units, representing the remaining 59.4% limited partner interest in the Partnership.

Net income (loss) per common unit. 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 4). 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).

5. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

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, prior to the actual conversion, 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, prior to the actual conversion, conversion of the Series A Preferred units.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands except per-unit amounts	2018	2017	2018	2017
Net income (loss) attributable to Western Gas Partners, LP	$154,646	$143,506	$336,717	$418,846
Series A Preferred units interest in net (income) loss [(1)]	—	—	—	(42,373)
General partner interest in net (income) loss	(88,551)	(78,376)	(256,166)	(222,903)
Common and Class C limited partners' interest in net income (loss)	$66,095	$65,130	$80,551	$153,570
Net income (loss) allocable to common units [(1)]	$59,732	$57,448	$69,638	$132,545
Net income (loss) allocable to Class C units [(1)]	6,363	7,682	10,913	21,025
Common and Class C limited partners' interest in net income (loss)	$66,095	$65,130	$80,551	$153,570
Net income (loss) per unit				
Common units – basic and diluted [(2)]	$0.39	$0.38	$0.46	$0.91
Weighted-average units outstanding				
Common units – basic and diluted	152,609	152,602	152,605	145,371
Excluded due to anti-dilutive effect:				
Class C units [(2)]	13,921	12,873	13,652	12,660
Series A Preferred units assuming conversion to common units [(2)]	—	—	—	7,227

(1) Adjusted to reflect amortization of the beneficial conversion features.

(2) The impact of Class C units would be anti-dilutive for all periods presented and the conversion of Series A Preferred units would be anti-dilutive for the nine months ended September 30, 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, all remaining Series A Preferred units converted into common units on a one-for-one basis.

6. 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 natural gas, condensate and NGLs to Anadarko. Anadarko sells such natural gas, condensate and NGLs as an agent on behalf of either the Partnership or the Partnership's customers. When such sales are on the Partnership's customers' behalf, the Partnership recognizes associated service revenues and cost of product expense. When such sales are on the Partnership's behalf, the Partnership recognizes product sales revenues based on the Anadarko sales price to the third party and cost of product expense associated with these sales activities.
In addition, the Partnership purchases natural gas, condensate and NGLs 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.

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 $300.9 million and $325.2 million at September 30, 2018, and December 31, 2017, 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, percent-of-product 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. The Partnership's net gains (losses) on commodity price swap agreements were $(3.7) million and $(6.4) million for the three and nine months ended September 30, 2018, respectively, and $(1.0) million and $(0.6) million for the three and nine months ended September 30, 2017, respectively, and are reported in the consolidated statements of operations as affiliate Product sales in 2018 and as affiliate Product sales and Cost of product expense in 2017 (see Note 1).

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Revenues or costs attributable to volumes sold and purchased during 2017 and 2018 for the DJ Basin complex and 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 its consolidated statement of equity and partners' capital for an amount equal to (i) the amount by which the swap price for product sales exceeds the applicable market price in the tables below, minus (ii) the amount by which the swap price for product purchases exceeds the market price in the tables below. For the nine months ended September 30, 2018, the capital contribution from Anadarko was $40.7 million. The tables below summarize the swap prices compared to the forward market prices:

	DJ Basin Complex		
per barrel except natural gas	2017 - 2018 Swap Prices	2017 Market Prices [(1)]	2018 Market Prices [(1)]
Ethane	$18.41	$ 5.09	$ 5.41
Propane	47.08	18.85	28.72
Isobutane	62.09	26.83	32.92
Normal butane	54.62	26.20	32.71
Natural gasoline	72.88	41.84	48.04
Condensate	76.47	45.40	49.36
Natural gas (per MMBtu)	5.96	3.05	2.21

	MGR Assets		
per barrel except natural gas	2017 - 2018 Swap Prices	2017 Market Prices [(1)]	2018 Market Prices [(1)]
Ethane	$23.11	$ 4.08	$ 2.52
Propane	52.90	19.24	25.83
Isobutane	73.89	25.79	30.03
Normal butane	64.93	25.16	29.82
Natural gasoline	81.68	45.01	47.25
Condensate	81.68	53.55	56.76
Natural gas (per MMBtu)	4.87	3.05	2.21

(1) Represents the New York Mercantile Exchange forward strip price as of December 1, 2016, and December 20, 2017, for the 2017 Market Prices and 2018 Market Prices, respectively, 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 41% and 37% for the three and nine months ended September 30, 2018, respectively, and 33% and 34% for the three and nine months ended September 30, 2017, respectively. The Partnership's natural gas processing throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 35% for both the three and nine months ended September 30, 2018, and 39% and 42% for the three and nine months ended

September 30, 2017, respectively. The Partnership’s crude oil, NGL and produced water gathering, treating, transportation and disposal throughput (excluding equity investment throughput) attributable to production owned or controlled by Anadarko was 77% and 71% for the three and nine months ended September 30, 2018, respectively, and 54% and 50% for the three and nine months ended September 30, 2017, respectively.

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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 that acts as an agent in the sale to a third party. 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.

WES LTIP. The general partner awards phantom units under the Western Gas Partners, LP 2017 Long-Term Incentive Plan, effective October 17, 2017. Awards granted prior to October 17, 2017, were awarded under the Western Gas Partners, LP 2008 Long-Term Incentive Plan. These awards are primarily granted 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, 2018 and 2017, and $0.3 million for each of the nine months ended September 30, 2018 and 2017.

Anadarko Incentive Plan. General and administrative expenses included $1.4 million and $5.2 million for the three and nine months ended September 30, 2018, respectively, and $1.2 million and $3.2 million for the three and nine months ended September 30, 2017, 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 Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan ("Anadarko Incentive Plan"). Of this amount, $4.3 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, 2018.

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

	Nine Months Ended September 30,	
thousands	2018	2017
Cash consideration	$254	$3,910
Net carrying value	(254)	(5,283)
Partners' capital adjustment	$—	$(1,373)

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. For periods prior to January 1, 2018, the cash receipts resulting from such reimbursements were presented as "Contributions in aid of construction costs from affiliates" within the investing section of the consolidated statements of cash flows. As discussed in Recently adopted accounting standards in Note 1, upon adoption of Topic 606, affiliate reimbursements of capital costs are reflected as contract liabilities upon receipt, amortized to Service revenues – fee based over the expected period of customer benefit, and presented within the operating section of the consolidated statements of cash flows.

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6. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Summary of affiliate transactions. The following table summarizes material affiliate transactions:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2018	2017	2018	2017
Revenues and other [1]	$274,514	$351,127	$766,179	$982,595
Equity income, net – affiliates [1]	43,110	21,519	102,752	62,708
Cost of product [1]	46,971	22,902	131,428	60,497
Operation and maintenance [2]	25,145	18,110	68,830	53,661
General and administrative [3]	11,579	10,140	34,371	29,040
Operating expenses	83,695	51,152	234,629	143,198
Interest income [4]	4,225	4,225	12,675	12,675
Interest expense [5]	—	—	—	71
Settlement of the Deferred purchase price obligation – Anadarko [6]	—	—	—	(37,346)
Distributions to unitholders [7]	130,249	118,082	381,617	331,654
Above-market component of swap agreements with Anadarko	12,601	18,049	40,722	46,719

(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 acquisition of 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 Anadarko Incentive Plan within this Note 6).

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

(5) Includes amounts related to the Deferred purchase price obligation - Anadarko (see Note 3 and Note 10).

(6) Represents the cash payment to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko (see Note 3).

(7) Represents distributions paid under the partnership agreement (see Note 4 and Note 5).

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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7. PROPERTY, PLANT AND EQUIPMENT

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

thousands	Estimated Useful Life	September 30, 2018	December 31, 2017
Land	n/a	$4,653	$4,450
Gathering systems and processing complexes	3 to 47 years	7,883,265	7,113,114
Pipelines and equipment	15 to 45 years	137,769	137,644
Assets under construction	n/a	856,092	579,501
Other	3 to 40 years	30,976	29,826
Total property, plant and equipment		8,912,755	7,864,535
Less accumulated depreciation		2,494,121	2,133,644
Net property, plant and equipment		$6,418,634	$5,730,891

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, 2018, the Partnership recognized impairments of $152.7 million, including impairments of $125.9 million at the Third Creek gathering system and $8.1 million at the Kitty Draw gathering system. These assets were impaired to their estimated salvage values of $1.8 million and zero, respectively, using the market approach and Level 3 fair value inputs, due to the shutdown of the systems. See Note 1 for further information. The remaining $18.7 million of impairments was primarily related to (i) a $10.9 million impairment at the GNB NGL pipeline, which was impaired to its estimated fair value of $10.0 million using the income approach and Level 3 fair value inputs, and (ii) a $5.6 million impairment related to an idle facility at the Chipeta complex, which was impaired to its estimated salvage value of $1.5 million using the market approach and Level 3 fair value inputs.
During the year ended December 31, 2017, the Partnership recognized impairments of $178.4 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. The remaining $19.6 million of impairments was primarily related to (i) an $8.2 million impairment due to the cancellation of a plant project at the Hilight system, (ii) 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, (iii) a $3.1 million impairment of the Fort Union equity investment, (iv) 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 (v) the cancellation of a pipeline project in West Texas.

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8. EQUITY INVESTMENTS

The following table presents the activity in the Partnership's equity investments for the nine months ended September 30, 2018:

thousands	Fort Union	White Cliffs	Rendezvous	Mont Belvieu JV	TEFR Interests	Whitethorn	Cactus II	Total
Balance at December 31, 2017	$7,030	$44,945	$ 42,528	$110,299	$361,409	$—	$—	$566,211
Acquisitions	—	—	—	—	—	150,563	11,295	161,858
Investment earnings (loss), net of amortization	(892)	8,547	635	22,916	47,736	23,810	—	102,752
Contributions	—	1,278	—	—	24,680	7,069	34,436	67,463
Capitalized interest	—	—	—	—	—	—	516	516
Distributions	(194)	(8,111)	(2,091)	(22,945)	(43,989)	(16,497)	—	(93,827)
Distributions in excess of cumulative earnings [(1)]	(2,889)	(3,109)	(2,015)	(3,305)	(6,779)	—	—	(18,097)
Balance at September 30, 2018	$3,055	$43,550	$ 39,057	$106,965	$383,057	$164,945	$46,247	$786,876

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

9. COMPONENTS OF WORKING CAPITAL

A summary of accounts receivable, net is as follows:

thousands	September 30, 2018	December 31, 2017
Trade receivables, net	$ 224,818	$ 160,387
Other receivables, net	168	45
Total accounts receivable, net	$ 224,986	$ 160,432

A summary of other current assets is as follows:

thousands	September 30, 2018	December 31, 2017
Natural gas liquids inventory	$ 11,212	$ 10,788
Imbalance receivables	3,829	1,640
Prepaid insurance	3,101	2,388
Contract assets	2,748	—
Other	5,080	—
Total other current assets	$ 25,970	$ 14,816

9. COMPONENTS OF WORKING CAPITAL (CONTINUED)

A summary of accrued liabilities is as follows:

thousands	September 30, 2018	December 31, 2017
Accrued interest expense	$ 54,546	$ 40,632
Short-term asset retirement obligations [1]	42,872	2,304
Short-term remediation and reclamation obligations	833	833
Income taxes payable	247	2,495
Contract liabilities	8,031	—
Other	7,757	1,635
Total accrued liabilities	$ 114,286	$ 47,899

(1) As of September 30, 2018, includes $40.2 million of short-term liabilities incurred during the second quarter of 2018 related to the shutdowns at the Third Creek and Kitty Draw gathering systems. See Note 1 for further information.

10. DEBT AND INTEREST EXPENSE

The following table presents the Partnership's outstanding debt:

	September 30, 2018			December 31, 2017		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
2.600% Senior Notes due 2018	$—	$—	$—	$350,000	$349,684	$350,631
5.375% Senior Notes due 2021	500,000	496,669	517,160	500,000	495,815	530,647
4.000% Senior Notes due 2022	670,000	669,020	668,198	670,000	668,849	684,043
3.950% Senior Notes due 2025	500,000	492,596	478,470	500,000	491,885	500,885
4.650% Senior Notes due 2026	500,000	495,592	492,502	500,000	495,245	520,144
4.500% Senior Notes due 2028	400,000	394,514	384,964	—	—	—
4.750% Senior Notes due 2028	400,000	395,806	391,532	—	—	—
5.450% Senior Notes due 2044	600,000	593,319	565,485	600,000	593,234	637,827
5.300% Senior Notes due 2048	700,000	686,601	645,643	—	—	—
5.500% Senior Notes due 2048	350,000	342,347	331,981	—	—	—
RCF	—	—	—	370,000	370,000	370,000
Total long-term debt	$4,620,000	$4,566,464	$4,475,935	$3,490,000	$3,464,712	$3,594,177

(1) Fair value is measured using the market approach and Level 2 inputs.

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10. DEBT AND INTEREST EXPENSE (CONTINUED)

Debt activity. The following table presents the debt activity of the Partnership for the nine months ended September 30, 2018:

thousands	Carrying Value
Balance at December 31, 2017	$ 3,464,712
RCF borrowings	320,000
Issuance of 4.500% Senior Notes due 2028	400,000
Issuance of 5.300% Senior Notes due 2048	700,000
Issuance of 4.750% Senior Notes due 2028	400,000
Issuance of 5.500% Senior Notes due 2048	350,000
Repayment of 2.600% Senior Notes due 2018	(350,000)
Repayments of RCF borrowings	(690,000)
Other	(28,248)
Balance at September 30, 2018	$ 4,566,464

Senior Notes. In August 2018, the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 were offered to the public at prices of 99.818% and 98.912%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.885% and 5.652%, respectively. Interest is paid on each such series semi-annually on February 15 and August 15 of each year, beginning February 15, 2019. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the senior unsecured revolving credit facility ("RCF") and for general partnership purposes, including to fund capital expenditures.

In March 2018, the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 were offered to the public at prices of 99.435% and 99.169%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.682% and 5.431%, respectively. Interest is paid on each such series semi-annually on March 1 and September 1 of each year, beginning September 1, 2018. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.

At September 30, 2018, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.

Revolving credit facility. In February 2018, the Partnership entered into the five-year $1.5 billion RCF by amending and restating the $1.2 billion credit facility that was originally entered into in February 2014. The RCF is expandable to a maximum of $2.0 billion, matures in February 2023, with options to extend maturity by up to two additional one year increments, and bears interest at the London Interbank Offered Rate ("LIBOR"), plus applicable margins ranging from 1.00% to 1.50%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) LIBOR plus 1.00%, in each case plus applicable margins currently ranging from zero to 0.50%, based upon the Partnership's senior unsecured debt rating. The Partnership is required to pay a quarterly facility fee ranging from 0.125% to 0.250% of the commitment amount (whether used or unused), also based upon its senior unsecured debt rating.

As of September 30, 2018, the Partnership had no outstanding borrowings and $4.6 million in outstanding letters of credit, resulting in $1,495.4 million available borrowing capacity under the RCF. As of September 30, 2018 and 2017, the interest rate on any outstanding RCF borrowings was 3.56% and 2.54%, respectively. The facility fee rate was 0.20% at September 30, 2018 and 2017. At September 30, 2018, the Partnership was in compliance with all covenants under the RCF.

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10. 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	2018	2017	2018	2017
Third parties				
Long-term debt	$(52,935)	$(35,992)	$(142,612)	$(105,772)
Amortization of debt issuance costs and commitment fees	(2,023)	(1,667)	(6,083)	(4,942)
Capitalized interest	6,967	2,115	17,032	3,991
Total interest expense – third parties	(47,991)	(35,544)	(131,663)	(106,723)
Affiliates				
Deferred purchase price obligation – Anadarko[1]	—	—	—	(71)
Total interest expense – affiliates	—	—	—	(71)
Interest expense	$(47,991)	$(35,544)	$(131,663)	$(106,794)

(1) See Note 3 for a discussion of the Deferred purchase price obligation - Anadarko.

11. COMMITMENTS AND CONTINGENCIES

Litigation and legal proceedings. In February 2017, DBJV, at the time a 50/50 joint venture between a third party and the Partnership, initiated an arbitration against SWEPI LP ("SWEPI") for breach of a 2007 gas gathering agreement between it and DBJV (the "GGA"). Specifically, DBJV sought to collect certain gathering fees under the GGA for the period January 1, 2016 to July 1, 2017. SWEPI disputed DBJV's calculation of the cost of service based rate and filed a counterclaim alleging overpayment of fees under the GGA for the years 2013 through 2015. As part of the adoption of Topic 606 (see Note 1), during the first quarter of 2018, the Partnership recorded a $7.5 million contract liability and reduced total equity and partners' capital related to the counterclaim for the years 2013 through 2015 under the GGA revenue contract. The arbitration hearing concluded on June 27, 2018. On September 14, 2018, the panel issued a binding non-appealable decision awarding no damages to either DBJV or SWEPI. As such, during the third quarter of 2018, the previously recorded contract liability was reversed, resulting in a $7.5 million increase to Service revenues - fee based in the consolidated statements of operations.
In addition, from time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which the final disposition could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to construction and 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 equipment supporting the Partnership's operations, for which Anadarko charges the Partnership lease expense. The leases for the corporate offices and shared field offices extend through 2028 and 2033, respectively. Lease expense charged to the Partnership associated with these lease arrangements was $14.6 million and $40.5 million for the three and nine months ended September 30, 2018, respectively, and $12.0 million and $32.7

million for the three and nine months ended September 30, 2017, 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 2017 Form 10-K as filed with the SEC on February 16, 2018.

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) that 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, percent-of-product 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;

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- environmental liabilities;
- 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 the 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, transportation and disposal 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 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 2017 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 assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania, Texas and New Mexico. 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. In addition, in our capacity as a processor of natural gas, we also buy and sell natural gas, NGLs and condensate on behalf of ourselves and as agent for our customers under certain of our contracts. We provide these midstream services for Anadarko, as well as for third-party producers and customers. As of September 30, 2018, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems [1]	12	3	3	2
Treating facilities	19	3	—	3
Natural gas processing plants/trains	20	4	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	2

[1] Includes the DBM water systems.

Significant financial and operational events during the nine months ended September 30, 2018, included the following:

- In August 2018, we completed an offering of $400.0 million aggregate principal amount of 4.750% Senior Notes due 2028 and $350.0 million aggregate principal amount of 5.500% Senior Notes due 2048. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures. See Liquidity and Capital Resources within this Item 2 for additional information.

- In June 2018, we acquired a 20% interest in Whitethorn and a 15% interest in Cactus II, both from third parties. See Acquisitions and Divestitures below for additional information.

- In March 2018, we completed an offering of $400.0 million aggregate principal amount of 4.500% Senior Notes due 2028 and $700.0 million aggregate principal amount of 5.300% Senior Notes due 2048. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures. See Liquidity and Capital Resources within this Item 2 for additional information.

- In February 2018, we entered into the five-year $1.5 billion (expandable to $2.0 billion) RCF by amending and restating the $1.2 billion credit facility originally entered into in February 2014. See Liquidity and Capital Resources within this Item 2 for additional information.

- We raised our distribution to $0.965 per unit for the third quarter of 2018, representing a 2% increase over the distribution for the second quarter of 2018 and a 7% increase over the distribution for the third quarter of 2017.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,850 MMcf/d and 3,758 MMcf/d for the three and nine months ended September 30, 2018, respectively, representing a 12% and 4% increase, respectively, compared to the same periods in 2017.

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- Throughput for crude oil, NGL and produced water assets totaled 421 MBbls/d and 341 MBbls/d for the three and nine months ended September 30, 2018, respectively, representing a 101% and 82% increase, respectively, compared to the same periods in 2017.

- Operating income (loss) was $200.3 million for the three months ended September 30, 2018, representing a 12% increase compared to the same period in 2017. Operating income (loss) was $463.2 million for the nine months ended September 30, 2018, representing a 12% decrease compared to the same period in 2017.

- Adjusted gross margin for natural gas assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $1.03 per Mcf and $0.99 per Mcf for the three and nine months ended September 30, 2018, respectively, representing a 6% and 8% increase, respectively, compared to the same periods in 2017.

- Adjusted gross margin for crude oil, NGL and produced water assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $1.76 per Bbl and $1.71 per Bbl for the three and nine months ended September 30, 2018, respectively, representing a 13% and 17% decrease, respectively, compared to the same periods in 2017.

Colorado ballot initiative. The Colorado general election ballot in November 2018 includes Proposition 112, which, if passed, would amend the Colorado Revised Statutes to require that certain new oil and gas development on non-federal lands take place a minimum distance of 2,500 feet from occupied buildings such as homes, schools, and hospitals, and other areas designated as vulnerable. Such setbacks would effectively ban new oil and gas drilling and hydraulic fracturing on a substantial portion of Colorado's non-federal lands. If Proposition 112 passes, and is not amended or repealed by the state legislature, demand for our midstream services in Colorado is expected to be significantly reduced. If this occurs, we anticipate reallocating capital away from Colorado in order to serve Anadarko's revised U.S. onshore production plans, which we expect would focus on the Delaware Basin and the acceleration of emerging opportunities in Wyoming's Powder River Basin.

Significant item affecting comparability. On January 1, 2018, we adopted Revenue from Contracts with Customers (Topic 606) ("Topic 606"). The comparative historical financial information has not been adjusted and continues to be reported under Revenue Recognition (Topic 605). The following tables summarize the impact of adopting Topic 606 on the consolidated statements of operations:

	Three Months Ended September 30, 2018		
thousands	As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$409,106	$396,161	$ 12,945
Service revenues – product based	22,735	—	22,735
Product sales	75,150	366,603	(291,453)
Expenses			
Cost of product	105,966	353,641	(247,675)
Operation and maintenance	111,359	111,327	32
Depreciation and amortization	82,553	81,824	729
Income tax (benefit) expense	1,517	1,580	(63)

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thousands	Nine Months Ended September 30, 2018 As Reported	Without Adoption of Topic 606	Effect of Change Increase / (Decrease)
Revenues			
Service revenues – fee based	$1,146,099	$1,096,708	$ 49,391
Service revenues – product based	67,433	—	67,433
Product sales	217,738	978,127	(760,389)
Expenses			
Cost of product	303,518	940,936	(637,418)
Operation and maintenance	300,266	300,098	168
Depreciation and amortization	238,187	236,102	2,085
Impairments	152,708	152,663	45
Income tax (benefit) expense	3,301	3,361	(60)

For more information on the adoption of Topic 606, see Note 1—Description of Business and Basis of Presentation in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

ACQUISITIONS AND DIVESTITURES

Whitethorn LLC acquisition. In June 2018, we acquired a 20% interest in Whitethorn LLC, which owns a crude oil and condensate pipeline that originates in Midland, Texas and terminates in Sealy, Texas (the “Midland-to-Sealy pipeline”) and related storage facilities (collectively referred to as “Whitethorn”). A third party operates Whitethorn and oversees the related commercial activities. In connection with our investment in Whitethorn, we will share proportionally in the commercial activities. We acquired our 20% interest via a $150.6 million net investment, which was funded with cash on hand and is accounted for under the equity method. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Cactus II acquisition. In June 2018, we acquired a 15% interest in Cactus II, which will own a crude oil pipeline operated by a third party (the “Cactus II pipeline”) connecting West Texas to the Corpus Christi area. The Cactus II pipeline is under construction and expected to become operational in the fourth quarter of 2019. We acquired our 15% interest from a third party via an initial net investment of $11.3 million, which represented our share of costs incurred up to the date of acquisition. The initial investment was funded with cash on hand and the interest in Cactus II is accounted for under the equity method. See Note 3—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

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 3—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 $16.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

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Presentation of Partnership assets. The term “Partnership assets” includes both the assets owned and the interests accounted for under the equity method by us as of September 30, 2018 (see Note 8—Equity Investments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q). Because Anadarko controls us through its control of WGP, which owns the entire interest in our general partner, 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 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. 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.

For those periods requiring recast, the consolidated financial statements for periods prior to our acquisition of the Partnership assets from Anadarko have been prepared from Anadarko’s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the Partnership assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being “our” historical financial results.

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 all remaining Series A Preferred units converted into common units on a one-for-one basis on May 2, 2017. See Note 5—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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
thousands	2018	2017	2018	2017
Total revenues and other (1)	$507,762	$574,695	$1,432,483	$1,616,338
Equity income, net – affiliates	43,110	21,519	102,752	62,708
Total operating expenses (1)	350,616	416,830	1,072,403	1,318,489
Gain (loss) on divestiture and other, net	65	72	351	135,017
Proceeds from business interruption insurance claims (2)	—	—	—	29,882
Operating income (loss)	200,321	179,456	463,183	525,456
Interest income – affiliates	4,225	4,225	12,675	12,675
Interest expense	(47,991)	(35,544)	(131,663)	(106,794)
Other income (expense), net	598	286	2,609	969
Income (loss) before income taxes	157,153	148,423	346,804	432,306
Income tax (benefit) expense	1,517	510	3,301	4,905
Net income (loss)	155,636	147,913	343,503	427,401
Net income attributable to noncontrolling interest	990	4,407	6,786	8,555
Net income (loss) attributable to Western Gas Partners, LP	$154,646	$143,506	$336,717	$418,846
Key performance metrics (3)				
Adjusted gross margin	$431,561	$344,416	$1,178,400	$1,009,520
Adjusted EBITDA	314,522	257,835	858,300	787,664
Distributable cash flow	248,156	231,859	701,391	695,587

(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 Significant item affecting comparability within this Item 2 and Note 6—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, Adjusted EBITDA 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, 2018” refer to the comparison of the three months ended September 30, 2018, to the three months ended September 30, 2017; any increases or decreases “for the nine months ended September 30, 2018” refer to the comparison of the nine months ended September 30, 2018, to the nine months ended September 30, 2017; and any increases or decreases “for the three and nine months ended September 30, 2018” refer to the comparison of these 2018 periods to the corresponding three and nine month periods ended September 30, 2017.

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Throughput

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)						
Gathering, treating and transportation	954	784	22 %	886	1,029	(14)%
Processing	2,844	2,588	10 %	2,820	2,528	12 %
Equity investment (1)	139	159	(13)%	144	160	(10)%
Total throughput for natural gas assets	3,937	3,531	11 %	3,850	3,717	4 %
Throughput attributable to noncontrolling interest for natural gas assets	87	104	(16)%	92	107	(14)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,850	3,427	12 %	3,758	3,610	4 %
Throughput for crude oil, NGL and produced water assets (MBbls/d)						
Gathering, treating, transportation and disposal	154	77	100 %	141	57	147 %
Equity investment (2)	267	132	102 %	200	130	54 %
Total throughput for crude oil, NGL and produced water assets	421	209	101 %	341	187	82 %

(1) Represents our 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput.

(2) Represents our 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEG and TEP throughput, 33.33% share of average FRP throughput and 20% share of average Whitethorn throughput.

Natural gas assets

Gathering, treating and transportation throughput increased by 170 MMcf/d for the three months ended September 30, 2018, primarily due to (i) increased production in the areas around the DBJV system (increase of 135 MMcf/d), (ii) increased throughput at the Bison facility due to a new contract effective April 2018 (increase of 36 MMcf/d) and (iii) increased production in the areas around the Marcellus Interest systems in 2018 and curtailments in the third quarter of 2017 (increase of 32 MMcf/d). These increases were partially offset by lower throughput at the Springfield gas gathering system due to weather-related well shut-ins (decrease of 28 MMcf/d).

Gathering, treating and transportation throughput decreased by 143 MMcf/d for the nine months ended September 30, 2018, primarily due to the Property Exchange in March 2017 (decrease of 114 MMcf/d) and the sale of the Helper and Clawson systems in June 2017 (decrease of 22 MMcf/d).

Processing throughput increased by 256 MMcf/d and 292 MMcf/d for the three and nine months ended September 30, 2018, respectively, primarily due to increased production in the areas around the DJ Basin and DBM complexes and the start-up of Train VI at the DBM complex in December 2017. In addition, for the nine months ended September 30, 2018, processing throughput increased at the MGR assets due to downtime in 2017. These increases were partially offset by lower throughput at the Chipeta complex due to downstream fractionation capacity constraints in the third quarter of 2018 and the expiration and non-renewal of a contract in September 2017.

Equity investment throughput decreased by 20 MMcf/d and 16 MMcf/d for the three and nine months ended September 30, 2018, respectively, primarily due to decreased throughput at the Fort Union and Rendezvous systems due to production declines in the area, as well as throughput being diverted from the Fort Union system to other nearby systems.

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Crude oil, NGL and produced water assets

Gathering, treating, transportation and disposal throughput increased by 77 MBbls/d and 84 MBbls/d for the three and nine months ended September 30, 2018, respectively, primarily due to increased throughput from the DBM water systems, which commenced operation during the second quarter of 2017.
Equity investment throughput increased by 135 MBbls/d and 70 MBbls/d for the three and nine months ended September 30, 2018, respectively, primarily due to (i) the acquisition of the interest in Whitethorn in June 2018 and (ii) increased volumes on FRP and TEP as a result of increased NGL production in the DJ Basin area.

Service Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
Service revenues – fee based	$409,106	$306,187	34 %	$1,146,099	$913,436	25 %
Service revenues – product based	22,735	—	NM	67,433	—	NM
Total service revenues	$431,841	$306,187	41 %	$1,213,532	$913,436	33 %

NM-Not Meaningful

Service revenues – fee based increased by $102.9 million for the three months ended September 30, 2018, primarily due to increases of (i) $12.9 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, (ii) $33.5 million at the DJ Basin complex due to increased throughput ($27.9 million) and a higher processing fee ($5.6 million) due to a new contract effective August 2017 and (iii) $22.3 million and $21.9 million at the DBJV system and DBM complex, respectively, due to increased throughput.
Service revenues – fee based increased by $232.7 million for the nine months ended September 30, 2018, primarily due to increases of (i) $49.4 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, (ii) $95.5 million at the DJ Basin complex due to increased throughput ($70.5 million) and a higher processing fee ($25.0 million) due to a new contract effective August 2017, (iii) $55.8 million at the DBM complex due to increased throughput, (iv) $20.9 million at the DBM water systems, which commenced operation during the second quarter of 2017 and (v) $18.5 million due to the Property Exchange in March 2017. These increases were partially offset by a decrease of $9.6 million at the Springfield system due to a lower cost of service rate.
Service revenues – product based increased by $22.7 million and $67.4 million for the three and nine months ended September 30, 2018, respectively, due to the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2. Under Topic 606, certain of our customer agreements result in revenues being recognized when the natural gas and/or NGLs are received from the customer as noncash consideration for the services provided. In addition, retained proceeds from sales of customer products where we are acting as their agent are included in Service revenues – product based.

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Product Sales

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages and per-unit amounts	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
Natural gas sales [(1)]	$20,686	$100,395	(79)%	$62,403	$273,256	(77)%
NGL sales [(1)]	54,464	158,746	(66)%	155,335	417,234	(63)%
Total Product sales	$75,150	$259,141	(71)%	$217,738	$690,490	(68)%
Gross average sales price per unit [(1)]:						
Natural gas (per Mcf)	$2.01	$2.89	(30)%	$2.15	$2.96	(27)%
Natural gas liquids (per Bbl)	34.43	22.99	50 %	32.09	21.63	48 %

(1) Includes the effects of commodity price swap agreements for the MGR assets and DJ Basin complex, excluding the amounts considered above market with respect to these swap agreements that were recorded as capital contributions in the consolidated statement of equity and partners' capital. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Natural gas sales decreased by $79.7 million for the three months ended September 30, 2018, primarily due to decreases of (i) $62.4 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, (ii) $8.0 million at the DBM complex due to a decrease in average price, partially offset by an increase in volumes sold and (iii) $4.6 million at the DJ Basin complex due to a decrease in the swap market price, partially offset by an increase in volumes sold.

Natural gas sales decreased by $210.9 million for the nine months ended September 30, 2018, primarily due to decreases of (i) $184.5 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2 and (ii) $7.4 million due to a decrease in average price and $9.3 million due to a system shutdown, both at the Hilight system (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).

NGL sales decreased by $104.3 million and $261.9 million for the three and nine months ended September 30, 2018, respectively, primarily due to decreases of $229.1 million and $575.9 million, respectively, from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2. These decreases were partially offset by increases of (i) $90.6 million and $227.9 million, respectively, at the DBM complex due to an increase in average price and volumes sold, (ii) $14.7 million and $39.1 million, respectively, at the DJ Basin complex due to an increase in the swap market price and volumes sold, (iii) $5.7 million and $15.0 million, respectively, at the Brasada complex due to volumes sold under a new sales agreement beginning January 1, 2018, and (iv) $3.8 million and $5.4 million, respectively, at the Hilight system due to an increase in average price. In addition, for the nine months ended September 30, 2018, NGL sales increased by (i) $6.7 million at the DBM water systems, which commenced operation during the second quarter of 2017 and (ii) $6.2 million at the Chipeta complex due to an increase in average price.

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Other Revenues

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
Other revenues	$771	$9,367	(92)%	$1,213	$12,412	(90)%

Other revenues decreased by $8.6 million and $11.2 million for the three and nine months ended September 30, 2018, respectively, primarily due to deficiency fees at the Chipeta complex in 2017. Upon adoption of Topic 606 on January 1, 2018, deficiency fees are recorded as Service revenues – fee based in the consolidated statements of operations (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).

Equity Income, Net – Affiliates

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
Equity income, net – affiliates	$43,110	$21,519	100%	$102,752	$62,708	64 %

For the three and nine months ended September 30, 2018, Equity income, net – affiliates increased by $21.6 million and $40.0 million, respectively, primarily due to (i) the acquisition of the interest in Whitethorn in June 2018 and (ii) increased volumes at the TEFR Interests. These increases were partially offset by a decrease in volumes at the Fort Union system.

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Cost of Product and Operation and Maintenance Expenses

thousands except percentages	Three Months Ended September 30, 2018	2017	Inc/ (Dec)	Nine Months Ended September 30, 2018	2017	Inc/ (Dec)
NGL purchases [1]	$75,705	$136,636	(45)%	$211,816	$359,616	(41)%
Residue purchases [1]	25,389	90,264	(72)%	72,461	256,387	(72)%
Other	4,872	12,323	(60)%	19,241	15,856	21 %
Cost of product	105,966	239,223	(56)%	303,518	631,859	(52)%
Operation and maintenance	111,359	79,536	40 %	300,266	229,444	31 %
Total Cost of product and Operation and maintenance expenses	$217,325	$318,759	(32)%	$603,784	$861,303	(30)%

(1) For the three and nine months ended September 30, 2017, includes the effects of commodity price swap agreements for the MGR assets and DJ Basin complex, excluding the amounts considered above market with respect to these swap agreements that were recorded as capital contributions in the consolidated statement of equity and partners’ capital. See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

NGL purchases decreased by $60.9 million and $147.8 million for the three and nine months ended September 30, 2018, respectively, primarily due to decreases of $191.2 million and $458.6 million, respectively, from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, partially offset by increases of (i) $97.9 million and $231.4 million, respectively, at the DBM complex due to an increase in average price and volumes purchased, (ii) $14.8 million and $41.2 million, respectively, at the DJ Basin complex due to an increase in average price and volumes purchased, (iii) $5.3 million and $13.5 million, respectively, at the Brasada complex due to volumes purchased under a new purchase agreement beginning January 1, 2018, (iv) $3.7 million and $6.1 million, respectively, at the Hilight system due to an increase in average price, and (v) $2.7 million and $6.6 million, respectively, at the DBM water systems, which commenced operation during the second quarter of 2017.

Residue purchases decreased by $64.9 million for the three months ended September 30, 2018, primarily due to decreases of (i) $56.1 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, (ii) $2.8 million at the DBM complex due to a decrease in average price, partially offset by an increase in volumes purchased, and (iii) $2.8 million at the MGR assets due to a decrease in average price.

Residue purchases decreased by $183.9 million for the nine months ended September 30, 2018, primarily due to decreases of (i) $172.1 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2, (ii) $5.9 million at the Hilight system due to a decrease in average price, and (iii) $5.8 million at the MGR assets due to a decrease in average price.

Other items decreased by $7.5 million for the three months ended September 30, 2018, primarily due to a decrease of $11.6 million from changes in imbalance positions primarily at the DBM complex, partially offset by an increase of $3.8 million at the DJ Basin complex due to changes in affiliate contract terms in August 2017.

Other items increased by $3.4 million for the nine months ended September 30, 2018, primarily due to an increase of $19.0 million at the DJ Basin complex due to changes in affiliate contract terms in August 2017, partially offset by decreases of (i) $9.3 million from changes in imbalance positions primarily at the DBM complex and (ii) $6.7 million from the adoption of Topic 606 as discussed under Significant item affecting comparability within this Item 2.

Operation and maintenance expense increased by $31.8 million and $70.8 million for the three and nine months ended September 30, 2018, respectively, primarily due to increases of (i) $10.3 million and $23.2 million, respectively, at the DBM complex primarily due to increases in utilities expense, surface maintenance and plant repairs, equipment rentals, and salaries and wages, (ii) $8.1 million and $21.2 million, respectively, at the DJ Basin complex primarily due to increases in surface maintenance and plant repairs and utilities expense, (iii) $7.2 million and $18.3 million, respectively, at the DBJV system primarily due to increases in surface maintenance and plant repairs, salaries and wages, and equipment rentals, and (iv) \$1.9 million and \$4.5 million, respectively, at the DBM water systems, which commenced operation during the second quarter of 2017.

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Other Operating Expenses

	Three Months Ended September 30,			Nine Months Ended September 30,		
thousands except percentages	2018	2017	Inc/ (Dec)	2018	2017	Inc/ (Dec)
General and administrative	$14,467	$12,158	19 %	$42,634	$35,402	20 %
Property and other taxes	10,954	11,215	(2)%	35,090	35,433	(1)%
Depreciation and amortization	82,553	72,539	14 %	238,187	216,272	10 %
Impairments	25,317	2,159	NM	152,708	170,079	(10)%
Total other operating expenses	$133,291	$98,071	36 %	$468,619	$457,186	3 %

General and administrative expenses increased by $2.3 million and $7.2 million for the three and nine months ended September 30, 2018, respectively, primarily due to (i) personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement and (ii) legal and consulting fees incurred in 2018. For the nine months ended September 30, 2018, these increases were partially offset by a decrease in bad debt expense.

Depreciation and amortization expense increased by $10.0 million for the three months ended September 30, 2018, primarily due to depreciation expense increases of $4.2 million and $3.0 million related to capital projects being placed into service at the DBJV system and the DBM complex, respectively.

Depreciation and amortization expense increased by $21.9 million for the nine months ended September 30, 2018, primarily due to (i) $12.3 million due to the Property Exchange in March 2017 and capital projects being placed into service at the DBJV system and (ii) $6.8 million related to capital projects being placed into service at the DBM complex.

Impairment expense for the three months ended September 30, 2018, was primarily due to impairments of (i) $10.9 million at the GNB NGL pipeline, (ii) $5.6 million at the Chipeta complex, (iii) $5.1 million at the Third Creek gathering system and (iv) $1.7 million at the Kitty Draw gathering system.

Impairment expense for the nine months ended September 30, 2018, was primarily due to impairments of (i) $125.9 million at the Third Creek gathering system and $8.1 million at the Kitty Draw gathering system (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), (ii) $10.9 million at the GNB NGL pipeline and (iii) $5.6 million at the Chipeta complex.

Impairment expense for the three months ended September 30, 2017, was primarily due to a $2.0 million impairment of an idle facility in northeast Wyoming.

Impairment expense for the nine months ended September 30, 2017, included (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. For further information on impairment expense for the periods presented, see Note 7—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

thousands except percentages	Three Months Ended September 30, 2018	2017	Inc/ (Dec)	Nine Months Ended September 30, 2018	2017	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	$(52,935)	$(35,992)	47 %	$(142,612)	$(105,772)	35 %
Amortization of debt issuance costs and commitment fees	(2,023)	(1,667)	21 %	(6,083)	(4,942)	23 %
Capitalized interest	6,967	2,115	NM	17,032	3,991	NM
Affiliates						
Deferred purchase price obligation – Anadarko[1]	—	—	— %	—	(71)	(100)%
Interest expense	$(47,991)	$(35,544)	35 %	$(131,663)	$(106,794)	23 %

(1) See Note 3—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 $12.4 million and $24.9 million for the three and nine months ended September 30, 2018, respectively, primarily due to (i) $13.8 million and $32.0 million, respectively, of interest incurred on the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 that were issued in March 2018 and (ii) $5.5 million of interest incurred on the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 that were issued in August 2018. These increases were partially offset by increases in capitalized interest of $4.9 million and $13.0 million for the three and nine months ended September 30, 2018, respectively, primarily due to continued construction and expansion at (i) the DJ Basin complex, including construction of the Latham processing plant beginning in 2018, (ii) the DBJV system, and (iii) the DBM complex, including construction of the Mentone processing plant beginning in the fourth quarter of 2017.

Income Tax (Benefit) Expense

thousands except percentages	Three Months Ended September 30, 2018	2017	Inc/ (Dec)	Nine Months Ended September 30, 2018	2017	Inc/ (Dec)
Income (loss) before income taxes	$157,153	$148,423	6 %	$346,804	$432,306	(20)%
Income tax (benefit) expense	1,517	510	197%	3,301	4,905	(33)%
Effective tax rate	1 %	— %		1 %	1 %	

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 all 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.

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KEY PERFORMANCE METRICS

thousands except percentages and per-unit amounts	Three Months Ended September 30, 2018	2017	Inc/ (Dec)	Nine Months Ended September 30, 2018	2017	Inc/ (Dec)
Adjusted gross margin for natural gas assets [(1)]	$363,536	$305,337	19 %	$1,019,061	$904,620	13 %
Adjusted gross margin for crude oil, NGL and produced water assets [(2)]	68,025	39,079	74 %	159,339	104,900	52 %
Adjusted gross margin [(3)]	431,561	344,416	25 %	1,178,400	1,009,520	17 %
Adjusted gross margin per Mcf for natural gas assets [(4)]	1.03	0.97	6 %	0.99	0.92	8 %
Adjusted gross margin per Bbl for crude oil, NGL and produced water assets [(5)]	1.76	2.03	(13)%	1.71	2.05	(17)%
Adjusted EBITDA [(3)]	314,522	257,835	22 %	858,300	787,664	9 %
Distributable cash flow [(3)]	248,156	231,859	7 %	701,391	695,587	1 %

(1) Adjusted gross margin for natural gas assets is calculated as total revenues and other for natural gas assets (less reimbursements for electricity-related expenses recorded as revenue), less 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 for natural gas assets to its most comparable GAAP measure below.

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

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

(4) Average for period. Calculated as Adjusted gross margin 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 oil, NGL and produced water assets, divided by total throughput (MBbls/d) for crude oil, NGL and produced water assets.

Adjusted gross margin. We define Adjusted gross margin attributable to Western Gas Partners, LP ("Adjusted gross margin") as total revenues and other (less reimbursements for electricity-related expenses recorded as revenue), less cost of product, 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 the midstream industry.

Adjusted gross margin increased by $87.1 million for the three months ended September 30, 2018, primarily due to (i) increased throughput and a higher processing fee at the DJ Basin complex, (ii) increased throughput at the DBM complex and DBJV and DBM water systems, and (iii) the acquisition of the interest in Whitethorn in June 2018. These increases were partially offset by decreases due to (i) the treatment of deficiency fees under Topic 606 related to the Chipeta complex (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) and (ii) a lower cost of service rate at the Springfield system.

Adjusted gross margin increased by $168.9 million for the nine months ended September 30, 2018, primarily due to (i) increased throughput and a higher processing fee at the DJ Basin complex, (ii) increased throughput at the DBM complex, (iii) the start-up of the DBM water systems during the second quarter of 2017, (iv) the Property Exchange in

March 2017 and (v) the acquisition of the interest in Whitethorn in June 2018. These increases were partially offset by decreases due to (i) a lower cost of service rate at the Springfield system and (ii) a system shutdown at the Hilight system (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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To facilitate investor and industry analyst comparisons between us and our peers, we also disclose Adjusted gross margin per Mcf for natural gas assets and Adjusted gross margin per Bbl for crude oil, NGL and produced water assets. Adjusted gross margin per Mcf for natural gas assets increased by $0.06 for the three months ended September 30, 2018, primarily due to increased throughput at the DBM complex and DBJV system. Adjusted gross margin per Mcf for natural gas assets increased by $0.07 for the nine months ended September 30, 2018, primarily due to (i) increased throughput at the DBM complex, which has a higher-than-average margin as compared to our other natural gas assets and (ii) the Property Exchange in March 2017.
Adjusted gross margin per Bbl for crude oil, NGL and produced water assets decreased by $0.27 and $0.34 for the three and nine months ended September 30, 2018, respectively, primarily due to (i) increased throughput at the DBM water systems, which have lower margins than our crude oil and NGL assets, and (ii) a lower cost of service rate at the Springfield oil gathering system. These decreases were partially offset by (i) higher distributions received from the TEFR Interests and the Mont Belvieu JV, and (ii) the acquisition of the interest in Whitethorn in June 2018.

Adjusted EBITDA. 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 industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Adjusted EBITDA increased by $56.7 million and $70.6 million for the three and nine months ended September 30, 2018, respectively, primarily due to (i) decreases of $133.3 million and $328.4 million, respectively, in cost of product (net of lower of cost or market inventory adjustments) and (ii) increases of $21.9 million and $31.4 million, respectively, in distributions from equity investments. These amounts were partially offset by (i) decreases of $66.9 million and $183.9 million, respectively, in total revenues and other, (ii) increases of $31.8 million and $70.8 million, respectively, in operation and maintenance expenses, and (iii) increases of $2.0 million and $5.2 million, respectively, in general and administrative expenses excluding non-cash equity-based compensation expense. The amounts for the nine months ended September 30, 2018, were also partially offset by a $29.9 million decrease in business interruption proceeds.

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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 Service revenues – fee based recognized in Adjusted EBITDA (less than) in excess of customer billings, 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 increased by $16.3 million for the three months ended September 30, 2018, primarily due to a $56.7 million increase in Adjusted EBITDA, partially offset by (i) a $17.3 million increase in net cash paid for interest expense, (ii) a $13.2 million increase in cash paid for maintenance capital expenditures, (iii) a $5.4 million decrease in the above-market component of the swap agreements with Anadarko, and (iv) $4.4 million of customer billings less than the amount recognized as Service revenues - fee based.

Distributable cash flow increased by $5.8 million for the nine months ended September 30, 2018, primarily due to (i) a $70.6 million increase in Adjusted EBITDA and (ii) a $7.5 million decrease in Series A Preferred unit distributions. These amounts were partially offset by (i) a $38.0 million increase in net cash paid for interest expense, (ii) a $28.0 million increase in cash paid for maintenance capital expenditures, and (iii) a $6.0 million decrease in the above-market component of the swap agreements with Anadarko.

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	2018	2017	2018	2017
Reconciliation of Operating income (loss) to Adjusted gross margin				
Operating income (loss)	$200,321	$179,456	$463,183	$525,456
Add:				
Distributions from equity investments	51,023	29,145	111,924	80,568
Operation and maintenance	111,359	79,536	300,266	229,444
General and administrative	14,467	12,158	42,634	35,402
Property and other taxes	10,954	11,215	35,090	35,433
Depreciation and amortization	82,553	72,539	238,187	216,272
Impairments	25,317	2,159	152,708	170,079
Less:				
Gain (loss) on divestiture and other, net	65	72	351	135,017
Proceeds from business interruption insurance claims	—	—	—	29,882
Equity income, net – affiliates	43,110	21,519	102,752	62,708
Reimbursed electricity-related charges recorded as revenues	17,455	14,323	50,139	42,338
Adjusted gross margin attributable to noncontrolling interest	3,803	5,878	12,350	13,189
Adjusted gross margin	$431,561	$344,416	$1,178,400	$1,009,520
Adjusted gross margin for natural gas assets	$363,536	$305,337	$1,019,061	$904,620
Adjusted gross margin for crude oil, NGL and produced water assets	68,025	39,079	159,339	104,900

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thousands	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Adjusted EBITDA				
Net income (loss) attributable to Western Gas Partners, LP	$154,646	$143,506	$336,717	$418,846
Add:				
Distributions from equity investments	51,023	29,145	111,924	80,568
Non-cash equity-based compensation expense	1,548	1,258	5,552	3,479
Interest expense	47,991	35,544	131,663	106,794
Income tax expense	1,517	510	3,301	4,905
Depreciation and amortization (1)	81,826	71,812	236,008	214,213
Impairments (1)	23,930	2,159	151,321	170,079
Other expense (1)	33	—	184	140
Less:				
Gain (loss) on divestiture and other, net	65	72	351	135,017
Equity income, net – affiliates	43,110	21,519	102,752	62,708
Interest income – affiliates	4,225	4,225	12,675	12,675
Other income (1)	592	283	2,592	960
Adjusted EBITDA	$314,522	$257,835	$858,300	$787,664
Reconciliation of Net cash provided by operating activities to Adjusted EBITDA				
Net cash provided by operating activities	$236,811	$211,947	$751,722	$645,099
Interest (income) expense, net	43,766	31,319	118,988	94,119
Uncontributed cash-based compensation awards	(55)	78	932	(94)
Accretion and amortization of long-term obligations, net	(1,257)	(1,055)	(3,883)	(3,194)
Current income tax (benefit) expense	(14)	395	247	1,023
Other (income) expense, net	(598)	(286)	(2,609)	(969)
Distributions from equity investments in excess of cumulative earnings – affiliates	5,592	7,034	18,097	16,255
Changes in assets and liabilities:				
Accounts receivable, net	57,535	56,335	64,544	46,972
Accounts and imbalance payables and accrued liabilities, net	(14,781)	(45,982)	(55,354)	(4,007)
Other items, net	(9,379)	3,181	(24,049)	3,065
Adjusted EBITDA attributable to noncontrolling interest	(3,098)	(5,131)	(10,335)	(10,605)
Adjusted EBITDA	$314,522	$257,835	$858,300	$787,664
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			$751,722	$645,099
Net cash used in investing activities			(1,160,684)	(514,797)
Net cash provided by (used in) financing activities			460,816	(335,792)

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

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thousands except Coverage ratio	Three Months Ended September 30, 2018	2017	Nine Months Ended September 30, 2018	2017
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	$154,646	$143,506	$336,717	$418,846
Add:				
Distributions from equity investments	51,023	29,145	111,924	80,568
Non-cash equity-based compensation expense	1,548	1,258	5,552	3,479
Non-cash settled interest expense, net (1)	—	—	—	71
Income tax (benefit) expense	1,517	510	3,301	4,905
Depreciation and amortization (2)	81,826	71,812	236,008	214,213
Impairments (2)	23,930	2,159	151,321	170,079
Above-market component of swap agreements with Anadarko (3)	12,601	18,049	40,722	46,719
Other expense (2)	33	—	184	140
Less:				
Recognized Service revenues – fee based (less than) in excess of customer billings (4)	4,397	—	536	—
Gain (loss) on divestiture and other, net	65	72	351	135,017
Equity income, net – affiliates	43,110	21,519	102,752	62,708
Cash paid for maintenance capital expenditures (2)	23,837	10,591	61,162	33,115
Capitalized interest	6,967	2,115	17,032	3,991
Cash paid for (reimbursement of) income taxes	—	—	(87)	189
Series A Preferred unit distributions	—	—	—	7,453
Other income (2)	592	283	2,592	960
Distributable cash flow	$248,156	$231,859	$701,391	$695,587
Distributions declared (5)				
Limited partners – common units	$147,268		$434,930	
General partner	82,971		242,133	
Total	$230,239		$677,063	
Coverage ratio	1.08 x		1.04 x	

(1) Includes amounts related to the Deferred purchase price obligation - Anadarko. See Note 3—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; impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to the Chipeta complex.

(3) See Note 6—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

(4) 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.

(5) Reflects cash distributions of $0.965 and $2.850 per unit declared for the three and nine months ended September 30, 2018, 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, 2018, 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 the 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 the RCF to pay distributions or fund other short-term working capital requirements.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our 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 2018 of $0.965 per unit, or $230.2 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution is payable on November 13, 2018, to unitholders of record at the close of business on October 31, 2018. 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 4—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 $13.6 million for the third quarter of 2018.

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 potential debt or equity securities offerings, 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, 2018, we had a $130.4 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, 2018, was primarily due to (i) the costs incurred related to continued construction and expansion at the DBJV system and the DBM and DJ Basin complexes and (ii) system shutdowns at the Hilight system and DJ Basin complex. See Note 1—Description of Business and Basis of Presentation and Note 9—Components of Working Capital in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q. As of September 30, 2018, we had $1,495.4 million available for borrowing under the RCF. See Note 10—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 2018, the general partner's Board of Directors has approved Estimated Maintenance Capital Expenditures (as defined in our partnership agreement) of $19.5 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	2018	2017
Acquisitions	$162,112	$159,208
Expansion capital expenditures	$887,843	$384,416
Maintenance capital expenditures	61,179	33,391
Total capital expenditures (1) (2)	$949,022	$417,807
Capital incurred (2)	$923,407	$504,286

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

(2) For the nine months ended September 30, 2018 and 2017, included $17.0 million and $4.0 million, respectively, of capitalized interest.

Acquisitions during 2018 included a 20% interest in Whitethorn, a 15% interest in Cactus II and equipment purchases from Anadarko. Acquisitions during 2017 included the Additional DBJV System Interest and equipment purchases from Anadarko. See Note 3—Acquisitions and Divestitures and Note 6—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 $531.2 million for the nine months ended September 30, 2018. Expansion capital expenditures increased by $503.4 million (including a $13.0 million increase in capitalized interest) for the nine months ended September 30, 2018, primarily due to increases of $322.9 million at the DBJV system, $204.7 million at the DJ Basin complex and $16.9 million at the Haley system, primarily due to pipe, compression and processing projects. These increases were partially offset by decreases of (i) $31.1 million at the DBM water systems, which commenced operation during the second quarter of 2017 and (ii) $13.8 million at the DBM complex due to the start-up of Train VI in December 2017. Maintenance capital expenditures increased by $27.8 million for the nine months ended September 30, 2018, primarily due to increases at the DJ Basin complex, DBJV system and DBM complex.

During the first quarter of 2018, we updated our estimated total capital expenditures for the year ending December 31, 2018, (including equity investments and our 75% share of Chipeta's capital expenditures, but excluding acquisitions) from an originally reported $1.0 billion to $1.1 billion, to a current range of $1.35 billion to $1.45 billion to reflect our acquisition of a 20% interest in Whitethorn and a 15% interest in Cactus II. Additionally, during the third quarter of 2018, we updated our estimated maintenance capital expenditures from a previously reported range of $90.0 million to $100.0 million, to a current range of $85.0 million to $95.0 million.

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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	2018	2017
Net cash provided by (used in):		
Operating activities	$751,722	$645,099
Investing activities	(1,160,684)	(514,797)
Financing activities	460,816	(335,792)
Net increase (decrease) in cash and cash equivalents	$51,854	$(205,490)

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2018, increased primarily due to the impact of changes in working capital items and increases in distributions from equity investments. Refer to Operating Results within this Item 2 for a discussion of our results of operations as compared to the prior periods.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2018, included the following:

- $949.0 million of capital expenditures, primarily related to construction and expansion at the DBJV system and the DBM and DJ Basin complexes;
- $161.9 million of cash paid for the acquisitions of the interests in Whitethorn and Cactus II;
- $68.0 million of capital contributions paid to Cactus II, the TEFR Interests, Whitethorn and White Cliffs for construction activities; and
- $18.1 million of distributions received from equity investments in excess of cumulative earnings.

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 plant 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;
- $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 incident at the DBM complex in 2015;
- $16.3 million of distributions received from equity investments in excess of cumulative earnings; and
- $3.9 million of cash paid for equipment purchases from Anadarko.

Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2018, included the following:

- $1.08 billion of net proceeds from the offering of the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 in March 2018, after underwriting and original issue discounts and offering costs, which were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures;

- $738.1 million of net proceeds from the offering of the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 in August 2018, after underwriting and original issue discounts and offering costs, which were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures;
- $690.0 million of repayments of outstanding borrowings under the RCF;
- $663.4 million of distributions paid to our unitholders;
- $350.0 million of principal repayment on the maturing 2.600% Senior Notes due August 2018;
- $316.8 million of borrowings under the RCF, net of extension costs, which were used for general partnership purposes, including to fund capital expenditures;
- $40.7 million of capital contributions from Anadarko related to the above-market component of swap agreements; and
- $9.4 million of distributions paid to the noncontrolling interest owner of Chipeta.

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;
- $250.0 million of borrowings under the RCF, which were used for general partnership purposes;
- $46.7 million of capital contributions from Anadarko related to the above-market component of swap agreements;
- $37.3 million of cash paid to Anadarko for the settlement of the Deferred purchase price obligation - Anadarko; and
- $9.0 million of distributions paid to the noncontrolling interest owner of Chipeta.

Debt and credit facility. As of September 30, 2018, the carrying value of our outstanding debt was $4.6 billion. See Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q.

Senior Notes. In August 2018, the 4.750% Senior Notes due 2028 and 5.500% Senior Notes due 2048 were offered to the public at prices of 99.818% and 98.912%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.885% and 5.652%, respectively. Interest is paid on each such series semi-annually on February 15 and August 15 of each year, beginning February 15, 2019. The net proceeds were used to repay the maturing 2.600% Senior Notes due August 2018, repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.
In March 2018, the 4.500% Senior Notes due 2028 and 5.300% Senior Notes due 2048 were offered to the public at prices of 99.435% and 99.169%, respectively, of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rates of the senior notes are 4.682% and 5.431%, respectively. Interest is paid on each such series semi-annually on March 1 and September 1 of each year, beginning September 1, 2018. The net proceeds were used to repay amounts outstanding under the RCF and for general partnership purposes, including to fund capital expenditures.
At September 30, 2018, we were in compliance with all covenants under the indentures governing our outstanding notes.

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Revolving credit facility. In February 2018, we entered into the five-year $1.5 billion RCF by amending and restating the $1.2 billion credit facility that was originally entered into in February 2014. The RCF is expandable to a maximum of $2.0 billion, matures in February 2023, with options to extend maturity by up to two additional one year increments, and bears interest at LIBOR, plus applicable margins ranging from 1.00% to 1.50%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.50%, or (c) LIBOR plus 1.00%, in each case plus applicable margins currently ranging from zero to 0.50%, based upon our senior unsecured debt rating. We are required to pay a quarterly facility fee ranging from 0.125% to 0.250% of the commitment amount (whether used or unused), also based upon our senior unsecured debt rating.
As of September 30, 2018, we had no outstanding borrowings and $4.6 million in outstanding letters of credit, resulting in $1,495.4 million available for borrowing under the RCF. At September 30, 2018, the interest rate on the RCF was 3.56% and the facility fee rate was 0.20%. At September 30, 2018, we were in compliance with all covenants under the RCF.

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 offering. As of September 30, 2018, we had issued no common units under the registration statement associated with the $500.0 million COP.

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 do not, however, 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, transportation and disposal 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, percent-of-product and keep-whole contracts, and are subject to performance risk thereunder. See Note 6—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, transportation and disposal agreements, our natural gas and NGL purchase agreements, Anadarko’s note payable to us, our omnibus agreement, the services and secondment agreement, the 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 10—Debt and Interest Expense and Note 11—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, 2018.

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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 11—Commitments and Contingencies and Note 10—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 a majority of our exposure to the commodity price risk inherent in our percent-of-proceeds, percent-of-product 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 20, 2017, we renewed these commodity price swap agreements through December 31, 2018, with an effective date of January 1, 2018. See Note 6—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 resulting in 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. The Federal Open Market Committee raised its target range for the federal funds rate three separate times during 2017 and three times during 2018. These increases, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. As of September 30, 2018, we had no 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 no change in net income (loss) and the fair value of the borrowings under the RCF at September 30, 2018.

We may incur additional variable-rate debt in the future, either under the 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, 2018.

Changes in Internal Control Over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended September 30, 2018, that have materially affected, or are 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, 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 (“LDAR requirements”) at its Fort Lupton facility in the DJ Basin complex and WGR Operating, LP, another wholly owned subsidiary of the Partnership, is in negotiations with the EPA with respect to alleged non-compliance with LDAR requirements 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. Additionally, in May 2018, DBM, a wholly owned subsidiary of the Partnership, entered into a consent agreement and final order with the EPA with respect to alleged non-compliance with certain Risk Management Plan regulations under the Clean Air Act at the DBM complex and agreed to pay a penalty of $226,000. 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 below and under Part I, Item 1A in our Form 10-K for the year ended December 31, 2017, 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, 2017, 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.

Changes in laws or regulations regarding hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and natural gas wells, which could decrease the need for our gathering and processing services.

While we do not conduct hydraulic fracturing, our customers do conduct such activities. Hydraulic fracturing is an essential and common practice used by many of our oil and natural gas exploration and production customers to stimulate production of natural gas and oil from dense subsurface rock formations such as shales. Hydraulic fracturing is typically regulated by state oil and natural-gas commissions, but, in recent years, several federal agencies have also asserted regulatory authority over and proposed or promulgated regulations governing certain aspects of the process. For example, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants.

Additionally, in Colorado, where 30% of our throughput for natural gas assets (excluding equity investment throughput) is generated, certain interest groups opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have from time to time pursued ballot initiatives that, if approved, would allow revisions to the state constitution or state laws in a manner that would make such exploration and production more difficult or costly in the future. Most recently, special interest groups in Colorado were successful in placing a ballot initiative known as Proposition 112 on the ballot for the November 2018 statewide election. If passed, Proposition 112 would require certain new oil and gas development on non-federal lands in the state, including hydraulic fracturing, take place a minimum distance of 2,500 feet from occupied buildings such as homes, schools, and hospitals, and other areas designated as vulnerable. Such setbacks would effectively ban new oil and gas drilling and hydraulic fracturing on a substantial portion of Colorado's non-federal lands, which we expect would significantly reduce demand for our midstream services in the state.

Furthermore, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states have adopted or are considering adopting legal requirements that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, and states could elect to prohibit high-volume hydraulic fracturing altogether, following the approach taken by the State of New York. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances."

If new or more stringent federal, state or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering and processing services. Moreover, increased regulation of the hydraulic fracturing process could also lead to greater opposition to, and litigation over, oil and natural gas production activities using hydraulic fracturing techniques.

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

PIK Class C units. During the nine months ended September 30, 2018, 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
2017			
December 31	261,394	$13,674	February 2018
2018			
March 31	272,988	$12,901	May 2018
June 30	267,164	12,998	August 2018

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 5—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).

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Exhibit Number	Description
2.11#	Purchase and Sale Agreement, dated as of March 2, 2015, by and among WGR Asset Holding Company LLC, Delaware Basin Midstream, LLC, Western Gas Partners, LP, and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 3, 2015, File No. 001-34046).
2.12#	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	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated November 9, 2017 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on November 9, 2017, File No. 001-34046).
3.6	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).
3.7	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, which is included as Exhibit A to Exhibit 4.2, to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011,

	File No. 001-34046).
4.5	Fourth Supplemental Indenture, dated as of June 28, 2012, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).

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Exhibit Number	Description
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A 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).
4.7	Fifth Supplemental Indenture, dated as of August 14, 2013, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.8	Form of 2.600% Senior Notes due 2018 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.9	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, which is included as Exhibit A to Exhibit 4.2, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.11	Seventh Supplemental Indenture, dated as of June 4, 2015, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 4, 2015, File No. 001-34046).
4.12	Form of 3.950% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A 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).
4.13	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, which is included as Exhibit A 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).
4.15	Ninth Supplemental Indenture, dated as of March 2, 2018, 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 March 2, 2018, File No. 001-34046).
4.16	Form of 4.500% Senior Notes due 2028 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A-1 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 2, 2018, File No. 001-34046).
4.17	Form of 5.300% Senior Notes due 2048 (incorporated by reference to Exhibit 4.3, which is included as Exhibit A-2 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K filed on March 2, 2018, File No. 001-34046).
4.18	Tenth Supplemental Indenture, dated as of August 9, 2018, by and between 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 9, 2018, File No. 001-34046).
4.19	Form of 4.750% Senior Notes due 2028 (incorporated by reference to Exhibit 4.2, which is included as Exhibit A-1 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K file on August 9, 2018, File No. 001-34046).
4.20	Form of 5.500% Senior Notes due 2048 (incorporated by reference to Exhibit 4.3, which is included as Exhibit A-2 to Exhibit 4.1, to Western Gas Partners, LP's Current Report on Form 8-K file on August 9, 2018, File No. 001-34046).
4.21	Registration Rights Agreement by and between Western Gas Partners, LP and the Purchasers party thereto, dated as of March 14, 2016, (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current

Report on Form 8-K filed on March 16, 2016, File No. 001-34046).

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Exhibit Number	Description
4.22	Consent and Conversion Agreement, dated as of February 22, 2017, by and among Western Gas Partners, LP 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).
10.1*†	Gas Gathering Agreement between Anadarko E&P Onshore LLC and Delaware Basin Midstream, LLC, dated October 8, 2018.
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.

† Portions of this exhibit, which was previously filed with the Securities and Exchange Commission, were omitted pursuant to a request for confidential treatment. The omitted portions were filed separately with the Securities and Exchange Commission.

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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

October 31, 2018

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

October 31, 2018

/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)