Western Gas Partners LP
Form 10-Q/A
February 03, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q/A
(Amendment No. 1)
(Mark One)

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

For the quarterly period ended June 30, 2015

Or

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

For the transition period from to

Commission file number: 001-34046

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

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

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

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

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

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o
	(Do not check if a smaller reporting company)		

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

There were 128,574,646 common units outstanding as of July 28, 2015.

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For purposes of this report, “we,” “us,” “our,” the “Partnership” or “Western Gas Partners” refers to Western Gas Partners, LP and its subsidiaries. “Anadarko” refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner.

Explanatory Note

We are filing this Amendment No. 1 on Form 10-Q/A (this “Form 10-Q/A”) to amend our Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, originally filed with the Securities and Exchange Commission (the “SEC”) on July 30, 2015 (the “Original Filing”), to restate our unaudited consolidated financial statements and related disclosures as of, and for the three and six months ended, June 30, 2015. This Form 10-Q/A also amends certain other items in the Original Filing, as noted below.

Restatement Background

In connection with the preparation of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015, we determined that there was an error in the impairment test calculation performed as of March 31, 2015. Specifically, the impact of our commodity price swap agreements with Anadarko was incorrectly included when performing an assessment to identify a triggering event that would necessitate a calculation to determine whether the net book value of certain midstream assets exceeded their fair value. We determined that the error caused a material understatement in our impairment expense for the quarter ended March 31, 2015.

As a result of the discovery of this error, on January 27, 2016, the Audit Committee of the Board of Directors of our general partner, after discussion with management and KPMG LLP, our independent registered public accounting firm, concluded that the unaudited consolidated financial statements included in our Quarterly Reports on Form 10-Q for the quarterly periods ended March 31, 2015, June 30, 2015, and September 30, 2015, should no longer be relied upon due to changes related to impairments.

Accordingly, we are restating our unaudited consolidated financial statements as of, and for the three and six months ended, June 30, 2015, to reflect an impairment charge in the first quarter of 2015 of $264.4 million related to the Red Desert complex, located in southwestern Wyoming. This impairment loss recorded as of March 31, 2015, also impacts depreciation and amortization for the three and six months ended June 30, 2015. See Note 1—Description of Business and Basis of Presentation (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for more information regarding the impact of this adjustment.

In connection with the need to restate our unaudited consolidated financial statements as a result of the error noted above, we have determined that it would be appropriate within this Form 10-Q/A to make adjustments for certain previously unrecorded immaterial adjustments. See Note 1—Description of Business and Basis of Presentation (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for more information regarding the impact of such adjustments.

This report on Form 10-Q/A is presented as of the filing date of the Original Filing and does not reflect events occurring after that date, or modify or update the information contained therein in any way other than as required to correct the error and record the adjustments described above.

Internal Control Consideration

The Chief Executive Officer and Chief Financial Officer of our general partner have determined that there was a deficiency in our internal control over financial reporting that constituted a material weakness, as defined by SEC regulations, at June 30, 2015. For a discussion of management’s evaluation of our disclosure controls and procedures and the material weakness identified, see Part I, Item 4 of this Form 10-Q/A.

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DEFINITIONS

As generally used within the energy industry and in this quarterly report on Form 10-Q/A, the identified terms have the following meanings:
Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.
Btu: British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Condensate: A natural gas liquid with a low vapor pressure mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Cryogenic: The process in which liquefied gases, such as liquid nitrogen or liquid helium, are used to bring volumes to very low temperatures (below approximately -238 degrees Fahrenheit) to separate natural gas liquids from natural gas. Through cryogenic processing, more natural gas liquids are extracted than when traditional refrigeration methods are used.
Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.
Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.
MBbls/d: One thousand barrels per day.
MMBtu: One million British thermal units.
MMcf/d: One million cubic feet per day.
Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.

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PART I. FINANCIAL INFORMATION (UNAUDITED)
Item 1. Financial Statements
WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

thousands except per-unit amounts	Three Months Ended June 30, 2015 (Restated)	2014 [1]	Six Months Ended June 30, 2015 (Restated)	2014 [1]
Revenues – affiliates				
Gathering, processing and transportation of natural gas and natural gas liquids	$150,221	$117,159	$289,626	$215,946
Natural gas, natural gas liquids and drip condensate sales	121,613	159,581	240,353	282,182
Other	132	843	302	1,571
Total revenues – affiliates	271,966	277,583	530,281	499,699
Revenues – third parties				
Gathering, processing and transportation of natural gas and natural gas liquids	91,234	68,763	173,484	130,989
Natural gas, natural gas liquids and drip condensate sales	52,589	9,822	99,521	25,886
Other	783	1,213	1,695	2,056
Total revenues – third parties	144,606	79,798	274,700	158,931
Total revenues	416,572	357,381	804,981	658,630
Equity income, net [2]	18,941	13,008	37,161	22,259
Operating expenses				
Cost of product [3]	147,232	122,318	286,657	217,709
Operation and maintenance [3]	70,048	65,440	138,007	116,534
General and administrative [3]	8,667	8,445	19,179	17,349
Property and other taxes	8,775	7,316	17,298	14,550
Depreciation and amortization	61,485	44,962	123,555	85,857
Impairments	1,268	343	273,892	1,533
Total operating expenses	297,475	248,824	858,588	453,532
Operating income (loss)	138,038	121,565	(16,446)	227,357
Interest income – affiliates	4,225	4,225	8,450	8,450
Interest expense [4]	(27,604)	(20,864)	(50,564)	(34,825)
Other income (expense), net	71	214	142	691
Income (loss) before income taxes	114,730	105,140	(58,418)	201,673
Income tax (benefit) expense	(1,710)	2,523	1,706	4,308
Net income (loss)	116,440	102,617	(60,124)	197,365
Net income attributable to noncontrolling interest	2,816	3,450	6,042	7,142
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Limited partners' interest in net income (loss):				
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Pre-acquisition net (income) loss allocated to Anadarko	—	(4,135)	(1,742)	(6,800)
General partner interest in net (income) loss [5]	(45,971)	(28,047)	(83,148)	(52,881)
Limited partners' interest in net income (loss) [5]	67,653	66,985	(151,056)	130,542
Net income (loss) per common unit – basic [6]	$0.46	$0.57	$(1.14)	$1.11
Net income (loss) per common unit – diluted [6]	0.46	0.57	(1.14)	1.11

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

(2) Income earned from equity investments is classified as affiliate. See Note 1.

(3) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $53.1 million and $97.0 million for the three and six months ended June 30, 2015, respectively, and $38.7 million and $58.0 million for the three and six months ended June 30, 2014, respectively. Operation and maintenance includes charges from Anadarko of $17.5 million and $32.9 million for the three and six months ended June 30, 2015, respectively, and $16.8 million and $29.4 million for the three and six months ended June 30, 2014, respectively. General and administrative includes charges from Anadarko of $7.3 million and $14.9 million for the three and six months ended June 30, 2015, respectively, and $6.9 million and $14.2 million for the three and six months ended June 30, 2014, respectively. See Note 5.

(4) Includes affiliate (as defined in Note 1) interest expense of $4.2 million and $5.6 million for the three and six months ended June 30, 2015, respectively, and zero for each of the three and six months ended June 30, 2014. See Note 2 and Note 9.

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

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

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

thousands except number of units	June 30, 2015 (Restated)	December 31, 2014 [1]
ASSETS		
Current assets		
Cash and cash equivalents	$87,768	$67,054
Accounts receivable, net [2]	172,663	109,243
Other current assets [3]	11,670	10,067
Total current assets	272,101	186,364
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	5,948,148	5,626,650
Less accumulated depreciation	1,426,801	1,055,207
Net property, plant and equipment	4,521,347	4,571,443
Goodwill	393,035	389,087
Other intangible assets	846,342	884,857
Equity investments	630,851	634,492
Other assets	31,172	28,289
Total assets	$6,954,848	$6,954,532
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [4]	$45,376	$54,232
Accrued ad valorem taxes	18,098	14,812
Accrued liabilities	149,188	170,789
Total current liabilities	212,662	239,833
Long-term debt	2,677,023	2,422,954
Deferred income taxes	5,332	45,656
Asset retirement obligations and other	120,041	111,714
Deferred purchase price obligation – Anadarko [5]	179,886	—
Total long-term liabilities	2,982,282	2,580,324
Total liabilities	3,194,944	2,820,157
Equity and partners' capital		
Common units (128,574,646 and 127,695,130 units issued and outstanding at June 30, 2015, and December 31, 2014, respectively)	2,867,428	3,119,714
Class C units (11,077,794 and 10,913,853 units issued and outstanding at June 30, 2015, and December 31, 2014, respectively)	712,040	716,957
General partner units (2,583,068 units issued and outstanding at June 30, 2015, and December 31, 2014)	112,099	105,725
Net investment by Anadarko	—	122,509
Total partners' capital	3,691,567	4,064,905
Noncontrolling interest	68,337	69,470
Total equity and partners' capital	3,759,904	4,134,375
Total liabilities, equity and partners' capital	$6,954,848	$6,954,532

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

(2)

Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $74.5 million and $64.7 million as of June 30, 2015, and December 31, 2014, respectively.

(3) Other current assets includes natural gas imbalance receivables from affiliates of zero and $0.2 million as of June 30, 2015, and December 31, 2014, respectively.

(4) Accounts and natural gas imbalance payables includes amounts payable to affiliates of zero and $0.1 million as of June 30, 2015, and December 31, 2014, respectively.

(5) See Note 2.

See accompanying Notes to Consolidated Financial Statements.

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

	Partners' Capital					
thousands	Net Investment by Anadarko	Common Units	Class C Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2014 [1]	$122,509	$3,119,714	$716,957	$105,725	$69,470	$4,134,375
Net income (loss)	1,742	(139,679)	(11,377)	83,148	6,042	(60,124)
Issuance of common units, net of offering expenses	—	57,376	—	—	—	57,376
Amortization of beneficial conversion feature of Class C units	—	(6,460)	6,460	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	(7,175)	(7,175)
Distributions to unitholders	—	(182,525)	—	(76,722)	—	(259,247)
Acquisitions from affiliates	(196,191)	21,915	—	—	—	(174,276)
Contributions of equity-based compensation from Anadarko	—	1,713	—	34	—	1,747
Net pre-acquisition contributions from (distributions to) Anadarko	30,096	—	—	—	—	30,096
Net distributions to Anadarko of other assets	—	(4,640)	—	(86)	—	(4,726)
Elimination of net deferred tax liabilities	41,844	—	—	—	—	41,844
Other	—	14	—	—	—	14
Balance at June 30, 2015 (Restated)	$—	$2,867,428	$712,040	$112,099	$68,337	$3,759,904

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

See accompanying Notes to Consolidated Financial Statements.

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

thousands	Six Months Ended June 30, 2015 (Restated)	2014 [1]
Cash flows from operating activities		
Net income (loss)	$(60,124)	$197,365
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	123,555	85,857
Impairments	273,892	1,533
Non-cash equity-based compensation expense	2,130	2,187
Deferred income taxes	1,288	2,218
Accretion and amortization of long-term obligations, net	7,070	1,358
Equity income, net [2]	(37,161)	(22,259)
Distributions from equity investment earnings [2]	39,034	26,793
Changes in assets and liabilities:		
(Increase) decrease in accounts receivable, net	(46,135)	(23,860)
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	(118)	4,267
Change in other items, net	(1,964)	4,247
Net cash provided by operating activities	301,467	279,706
Cash flows from investing activities		
Capital expenditures	(338,178)	(390,506)
Contributions in aid of construction costs from affiliates	—	182
Acquisitions from affiliates	(9,968)	(360,952)
Acquisitions from third parties	(3,514)	—
Investments in equity affiliates	(6,770)	(60,102)
Distributions from equity investments in excess of cumulative earnings [2]	8,538	9,848
Proceeds from the sale of assets to affiliates	700	—
Proceeds from the sale of assets to third parties	22	—
Net cash used in investing activities	(349,170)	(801,530)
Cash flows from financing activities		
Borrowings, net of debt issuance costs	769,694	1,076,895
Repayments of debt	(520,000)	(480,000)
Increase (decrease) in outstanding checks	(2,327)	2,517
Proceeds from the issuance of common and general partner units, net of offering expenses	57,376	92,588
Distributions to unitholders	(259,247)	(191,359)
Distributions to noncontrolling interest owner	(7,175)	(7,949)
Net contributions from Anadarko	30,096	39,033
Net cash provided by financing activities	68,417	531,725
Net increase (decrease) in cash and cash equivalents	20,714	9,901
Cash and cash equivalents at beginning of period	67,054	100,728
Cash and cash equivalents at end of period	$87,768	$110,629
Supplemental disclosures		
Acquisition of DBJV from Anadarko [3]	$174,276	$—
Net distributions to (contributions from) Anadarko of other assets	4,726	(43)

Interest paid, net of capitalized interest	42,165	26,346
Taxes paid (reimbursements received)	(138)	(340)
Capital lease asset transfer [4]	—	4,833

(1) Financial information has been recast to include the financial position and results attributable to the DBJV system. See Note 1 and Note 2.
(2) Income earned on, distributions from and contributions to equity investments are classified as affiliate. See Note 1.
(3) See Note 2.
(4) For the six months ended June 30, 2014, represents transfers of $4.6 million from other long-term assets associated with the capital lease component of a processing agreement.

See accompanying Notes to Consolidated Financial Statements.

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

General. Western Gas Partners, LP is a growth-oriented Delaware master limited partnership formed by Anadarko Petroleum Corporation in 2007 to acquire, own, develop and operate midstream energy assets.

For purposes of these consolidated financial statements, the "Partnership" refers to Western Gas Partners, LP and its subsidiaries. The Partnership's general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware master limited partnership formed by Anadarko Petroleum Corporation in September 2012 to own the Partnership's general partner, as well as a significant limited partner interest in the Partnership (see Western Gas Equity Partners, LP below). 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, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." "Equity investment throughput" refers to the Partnership's 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of the Partnership's 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014. The "MGR assets" include the Red Desert complex, the Granger straddle plant and the 22% interest in Rendezvous.

The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of June 30, 2015, the Partnership's assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	2	5	2
Natural gas treating facilities	10	5	—	1
Natural gas processing facilities	14	5	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipelines	1	—	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas. In June 2015, the Partnership completed the construction and commenced operations of Lancaster Train II, a processing plant located in the DJ Basin complex. In addition, the Partnership is constructing Trains IV and V, both processing plants, at the DBM complex (see Note 2), with operations expected to commence during the first and second halves of 2016, respectively.

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

Western Gas Equity Partners, LP. WGP owns the following types of interests in the Partnership: (i) the general partner interest and all of the incentive distribution rights ("IDRs") in the Partnership, both owned through WGP's 100% ownership of the Partnership's general partner and (ii) a significant limited partner interest (see Holdings of Partnership equity in Note 4). WGP has no independent operations or material assets other than its partnership interests in the Partnership.

Basis of presentation. 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. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership proportionately consolidates its 33.75% share of the assets, liabilities, revenues and expenses attributable to the Non-Operated Marcellus Interest systems and Anadarko-Operated Marcellus Interest systems and its 50% share of the assets, liabilities, revenues and expenses attributable to the Newcastle system and the DBJV system (see Note 2) in the accompanying consolidated financial statements. The 25% membership interest in Chipeta Processing LLC ("Chipeta") held by a third-party member is reflected within noncontrolling interest in the consolidated financial statements for all periods presented.

In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Management evaluates its estimates and related assumptions regularly, using historical experience and other methods considered reasonable. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revisions become known. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated financial statements, and certain prior-period amounts have been reclassified to conform to the current-year presentation.

Certain information and note disclosures commonly included in annual financial statements have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, the accompanying consolidated financial statements and notes should be read in conjunction with the Partnership's 2014 Form 10-K, as filed with the SEC on February 26, 2015. Management believes that the disclosures made are adequate to make the information not misleading.

Restatement of Previously Issued Financial Statements. In connection with the preparation of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015, the Partnership determined that there was an error in the impairment test calculation performed as of March 31, 2015. Specifically, the impact of the Partnership's commodity price swap agreements with Anadarko was incorrectly included when performing an assessment to identify a triggering event that would necessitate a calculation to determine whether the net book value of certain midstream assets exceeded their fair value. The Partnership determined that the error caused a material understatement in its impairment expense for the quarter ended March 31, 2015. Accordingly, the Partnership's unaudited consolidated financial statements as of, and for the three and six months ended, June 30, 2015, and notes thereto, have been restated to reflect an impairment charge of $264.4 million related to its Red Desert complex. The impairment loss recorded as of March 31, 2015, also impacts depreciation and amortization for the three and six months ended June 30, 2015.

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

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

The tables below outline the financial statement line items, including the net income (loss) per common unit (basic and diluted), as of and for the three and six months ended June 30, 2015, that were restated as a result of the correction of this error:

	Consolidated Statement of Income for the Three Months Ended June 30, 2015			Consolidated Statement of Income for the Six Months Ended June 30, 2015		
thousands except per-unit amounts	As Reported	Adjustments	As Restated	As Reported	Adjustments	As Restated
Depreciation and amortization [1]	$64,693	$(3,208)	$61,485	$126,763	$(3,208)	$123,555
Impairments [1]	1,268	—	1,268	9,490	264,402	273,892
Operating income (loss)	134,830	3,208	138,038	244,748	(261,194)	(16,446)
Income (loss) before income taxes	111,522	3,208	114,730	202,776	(261,194)	(58,418)
Income tax (benefit) expense	(1,816)	106	(1,710)	2,644	(938)	1,706
Net income (loss)	113,338	3,102	116,440	200,132	(260,256)	(60,124)
Net income (loss) attributable to Western Gas Partners, LP	110,522	3,102	113,624	194,090	(260,256)	(66,166)
General partner interest in net (income) loss	(45,915)	(56)	(45,971)	(87,908)	4,760	(83,148)
Limited partners' interest in net income (loss)	64,607	3,046	67,653	104,440	(255,496)	(151,056)
Net income (loss) per common unit – basic	$0.44	$0.02	$0.46	$0.70	$(1.84)	$(1.14)
Net income (loss) per common unit – diluted	0.44	0.02	0.46	0.70	(1.84)	(1.14)

(1) "As Reported" amounts previously included as a component of Depreciation, amortization and impairments in the Partnership's Original Filing.

	Consolidated Balance Sheet as of June 30, 2015		
thousands	As Reported	Adjustments	As Restated
Accumulated depreciation	$1,165,607	$261,194	$1,426,801
Net property, plant and equipment	4,782,541	(261,194)	4,521,347
Total assets	7,216,042	(261,194)	6,954,848
Accrued liabilities	149,589	(401)	149,188
Total current liabilities	213,063	(401)	212,662
Deferred income taxes	5,869	(537)	5,332
Total long-term liabilities	2,982,819	(537)	2,982,282
Total liabilities	3,195,882	(938)	3,194,944
Common units	3,102,772	(235,344)	2,867,428
Class C units	732,192	(20,152)	712,040
General partner units	116,859	(4,760)	112,099

Total partners' capital	3,951,823	(260,256)	3,691,567
Total equity and partners' capital	4,020,160	(260,256)	3,759,904
Total liabilities, equity and partners' capital	7,216,042	(261,194)	6,954,848

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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1. DESCRIPTION OF BUSINESS AND BASIS OF PRESENTATION (RESTATED) (CONTINUED)

	Consolidated Statement of Cash Flows for the Six Months Ended June 30, 2015		
thousands	As Reported	Adjustments	As Restated
Net income (loss)	$200,132	$(260,256)	$(60,124)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization [1]	126,763	(3,208)	123,555
Impairments [1]	9,490	264,402	273,892
Deferred income taxes	1,825	(537)	1,288
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	283	(401)	(118)

(1) "As Reported" amounts previously included as a component of Depreciation, amortization and impairments in the Partnership's Original Filing.

Adjustments to Previously Issued Financial Statements. The Partnership's unaudited consolidated statements of income also reflect adjustments for the following amounts, which previously reduced Operation and maintenance expense, to revenues related to Gathering, processing and transportation of natural gas and natural gas liquids: $13.2 million and $25.0 million for the three and six months ended June 30, 2015, respectively, and $10.0 million and $16.6 million for the three and six months ended June 30, 2014, respectively. Management determined that the third-party producer reimbursements received for electricity purchased by the Partnership are more appropriately classified as revenues, instead of as a reduction to Operation and maintenance expense. The correction of this error has no impact to Net income (loss), cash flows, or any non-GAAP metric the Partnership uses to evaluate its operations (see Key Performance Metrics under Part I, Item 2 of this Form 10-Q/A) and is not considered material to the Partnership's results of operations for the three and six months ended June 30, 2015 and 2014. In future filings, the Partnership will revise its previously reported consolidated financial statements for 2013, 2014 and 2015 to reflect these adjustments.

Presentation of Partnership assets. The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method (see Note 7) by the Partnership as of June 30, 2015. Because Anadarko controls the Partnership through its ownership and control of WGP, which owns the Partnership's entire general partner interest, each acquisition of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by the Partnership. Further, after an acquisition of Partnership assets from Anadarko, the Partnership may be required to recast its financial statements to include the activities of such Partnership assets from the date of common control. See Note 2.
For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership's acquisition of the Partnership assets from Anadarko have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the Partnership assets during the periods reported. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners.

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

Recently issued accounting standards. The Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-06, Earnings Per Share (Topic - 260)—Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions. This ASU contains guidance that addresses the historical earnings per unit presentation for master limited partnerships that apply the two-class method of calculating earnings per unit. When a general partner transfers or "drops down" net assets to a master limited partnership the transaction is accounted for as a transaction between entities under common control and the statements of operations are adjusted retrospectively to reflect the transaction. This ASU specifies that the historical earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner, and the previously reported earnings per unit of the limited partners should not change as a result of the dropdown transaction. The ASU also requires additional disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs for purposes of computing earnings per unit under the two-class method. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective approach, with early adoption permitted. While the Partnership believes it is currently in compliance with this ASU, it continues to evaluate the impact of the adoption of this ASU on its consolidated financial statements.

The FASB issued ASU 2015-03, Interest—Imputation of Interest (Subtopic 835-30)—Simplifying the Presentation of Debt Issuance Costs. This ASU will simplify the presentation of debt issuance costs by requiring such costs to be presented in the balance sheet as a reduction from the corresponding debt liability rather than as an asset. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective approach, with early adoption permitted. The Partnership does not expect the adoption to have a material impact on its consolidated financial statements.

The FASB issued ASU 2015-02, Consolidation—Amendments to the Consolidation Analysis. This ASU will simplify existing requirements by reducing the number of consolidation models and placing more emphasis on risk of loss when determining a controlling financial interest. The provisions will affect how limited partnerships and similar entities are assessed for consolidation, including the elimination of the presumption that a general partner should consolidate a limited partnership. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Partnership is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

The FASB issued ASU 2014-09, Revenue from Contracts with Customers. This ASU supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities—Oil and Gas—Revenue Recognition, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2018 and is required to be adopted using one of two retrospective application methods, with early adoption permitted in 2017. The Partnership is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

WESTERN GAS PARTNERS, LP
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2. ACQUISITIONS AND DIVESTITURES

The following table presents the acquisitions completed by the Partnership during 2015 and 2014, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Deferred Purchase Price Obligation - Anadarko	Borrowings	Cash On Hand	Common Units Issued to Anadarko	Class C Units Issued to Anadarko
TEFR Interests [1]	03/03/2014	Various [1]	$—	$350,000	$6,250	308,490	—
DBM [2]	11/25/2014	100 %	—	475,000	298,327	—	10,913,853
DBJV system [3]	03/02/2015	50 %	174,276	—	—	—	—

(1) The Partnership acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP from Anadarko. These assets gather and transport NGLs primarily from the Anadarko and Denver-Julesburg ("DJ") Basins. The interests in these entities are accounted for under the equity method of accounting. In connection with the issuance of the common units, the Partnership's general partner purchased 6,296 general partner units in exchange for the general partner's proportionate capital contribution of $0.4 million.

(2) The Partnership acquired Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, the Partnership changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM"). The assets acquired include cryogenic processing plants, a gas gathering system, and related facilities and equipment, which are collectively referred to as the "DBM complex" and serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. See DBM acquisition below for further information, including the preliminary allocation of the purchase price.

(3) The Partnership acquired Anadarko's interest in Delaware Basin JV Gathering LLC ("DBJV"), which owns a 50% interest in a gathering system and related facilities (the "DBJV system"). The DBJV system is located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties, Texas. The Partnership will make a cash payment on March 31, 2020, to Anadarko as consideration for the acquisition of DBJV. The Partnership currently estimates the future payment will be $282.8 million, the net present value of which was $174.3 million as of the acquisition date. See DBJV acquisition—Deferred purchase price obligation - Anadarko below.

DBJV acquisition. Because the acquisition of DBJV was a transfer of net assets between entities under common control, the Partnership's historical financial statements previously filed with the SEC have been recast in this Form 10-Q/A to include the results attributable to the DBJV system as if the Partnership owned DBJV for all periods presented. The consolidated financial statements for periods prior to the Partnership's acquisition of DBJV have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned DBJV during the periods reported.
The following table presents the impact of the DBJV system on revenues, equity income, net and net income (loss) as presented in the Partnership's historical consolidated statements of income:

	Three Months Ended June 30, 2014		
thousands	Partnership Historical [1]	DBJV System	Combined
Revenues	$341,756	$15,625	$357,381
Equity income, net	13,008	—	13,008
Net income (loss)	98,482	4,135	102,617

thousands	Six Months Ended June 30, 2014 Partnership Historical [1]	DBJV System	Combined
Revenues	$628,745	$29,885	$658,630
Equity income, net	22,259	—	22,259
Net income (loss)	189,609	7,756	197,365

(1) See Adjustments to Previously Issued Financial Statements in Note 1.

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WESTERN GAS PARTNERS, LP
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2. ACQUISITIONS AND DIVESTITURES (CONTINUED)

Deferred purchase price obligation - Anadarko. The consideration to be paid by the Partnership for the acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. The cash payment will be equal to eight multiplied by (a) the average of the Partnership's share in the Net Earnings (see definition below) of the DBJV system for the calendar years 2018 and 2019, less (b) the Partnership's share of all capital expenditures incurred for the DBJV system between March 1, 2015, and February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to the DBJV system on an accrual basis. As of the acquisition date, the estimated future payment obligation was $282.8 million, which had a net present value of $174.3 million, using a discount rate of 10%. As of June 30, 2015, the net present value of this obligation was $179.9 million and has been recorded on the consolidated balance sheet under Deferred purchase price obligation - Anadarko. Accretion expense for the three and six months ended June 30, 2015, was $4.2 million and $5.6 million, respectively, and has been recorded as a charge to interest expense. The fair value measurement was calculated using Level 3 inputs, which consisted of management's estimate of the Partnership's share of forecasted Net Earnings and capital expenditures for the DBJV system.

DBM acquisition. The DBM acquisition has been accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in the DBM acquisition were recorded in the consolidated balance sheet at their estimated fair values as of the acquisition date. Results of operations attributable to the DBM acquisition were included in the Partnership's consolidated statement of income beginning on the acquisition date in the fourth quarter of 2014.

The following is the preliminary allocation of the purchase price as of June 30, 2015, including $3.5 million of post-closing purchase price adjustments, to the assets acquired and liabilities assumed in the DBM acquisition as of the acquisition date, pending final review of certain support related to the acquired entity's assets and liabilities:

thousands		
Current assets	$63,020	
Property, plant and equipment	467,171	
Goodwill	282,999	
Other intangible assets	811,048	
Accounts payables	(17,679	)
Accrued liabilities	(38,684	)
Deferred income taxes	(1,342	)
Asset retirement obligations and other	(9,060	)
Total purchase price	$1,557,473	

The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the DBM acquisition using inputs that are not observable in the market and thus represent Level 3 inputs. The fair values of the processing plants, gathering system, and related facilities and equipment are based on market and cost approaches. The fair value of the intangible assets was determined using an income approach. Deferred taxes represent the tax effects of differences in the tax basis and acquisition-date fair value of the assets acquired and liabilities assumed.

Assets held for sale - Dew and Pinnacle systems. During the second quarter of 2015, the Dew and Pinnacle systems in East Texas satisfied criteria to be considered held for sale. At June 30, 2015, the Partnership's consolidated balance sheet included current assets of $2.2 million, long-term assets of $71.9 million, current liabilities of $4.2 million and long-term liabilities of $3.0 million associated with assets held for sale. The sale of these assets is expected to close on

July 31, 2015.

3. PARTNERSHIP DISTRIBUTIONS

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

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2014			
March 31	$0.625	$98,749	May 2014
June 30	0.650	105,655	August 2014
September 30	0.675	111,608	November 2014
December 31	0.700	126,044	February 2015
2015			
March 31	$0.725	$133,203	May 2015
June 30 (1)	0.750	139,736	August 2015

(1) On July 16, 2015, the Board of Directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders of $0.750 per unit, or $139.7 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 August 12, 2015, to unitholders of record at the close of business on July 31, 2015.

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

The Partnership issued the following PIK Class C units to APC Midstream Holdings, LLC ("AMH"), the holder of the Class C units, for the periods presented:

thousands except unit amounts For the Quarters Ended	PIK Class C Units	Implied Fair Value	Date of Distribution
2014			
December 31 (1)	45,711	$3,072	February 2015
2015			
March 31	118,230	$8,101	May 2015

(1) Prorated for the 37-day period the Class C units were outstanding during the fourth quarter of 2014.

4. EQUITY AND PARTNERS' CAPITAL (RESTATED)

Equity offerings. The Partnership completed the following public offerings of its common units during 2015 and 2014, including through its Continuous Offering Programs ("COP"):

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued (1)	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
2014					
$125.0 million COP (2)	1,133,384	23,132	$73.48	$1,738	$83,245
November 2014 equity offering (3)	8,620,153	153,061	70.85	18,615	602,967
2015					
$500.0 million COP (4)	873,525	—	$66.61	$782	$57,408

(1) Represents general partner units issued to the general partner in exchange for the general partner's proportionate capital contribution.

(2) Represents common and general partner units issued during the year ended December 31, 2014, pursuant to the Partnership's registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the "$125.0 million COP"). Gross proceeds generated (including the general partner's proportionate capital contributions) during the year ended December 31, 2014, were $85.0 million. The price per unit in the table above represents an average price for all issuances under the $125.0 million COP during the year ended December 31, 2014. As of December 31, 2014, the Partnership had used all the capacity to issue common units under this registration statement.

(3) Includes the issuance of 1,120,153 common units pursuant to the partial exercise of the underwriters' over-allotment option, the net proceeds from which were $77.0 million. Beginning with this partial exercise, the Partnership's general partner elected not to make a corresponding capital contribution to maintain its 2.0% interest in the Partnership.

(4) Represents common units issued during the six months ended June 30, 2015, pursuant to the Partnership's registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of common units (the "$500.0 million COP"). Gross proceeds generated during the three and six months ended June 30, 2015, were $26.7 million and $58.2 million, respectively. Commissions paid during the three and six months ended June 30, 2015, were $0.3 million and $0.6 million, respectively. The price per unit in the table above represents an average price for all issuances under the $500.0 million COP during the six months ended June 30, 2015.

Class C units. In connection with the closing of the DBM acquisition in November 2014, the Partnership issued 10,913,853 Class C units to AMH at a price of $68.72 per unit, generating proceeds of $750.0 million, pursuant to the Unit Purchase Agreement ("UPA") with Anadarko and AMH. All outstanding Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless the Partnership elects to convert such units earlier or Anadarko extends the conversion date. The Class C units were issued to partially fund the acquisition of DBM, and the UPA contains an optional redemption feature that provides the Partnership the ability to redeem up to $150.0 million of the Class C units within 10 days of the receipt of cash proceeds from an entity that is not an affiliate of the Partnership or AMH, if these cash proceeds were in relation to (i) the assets of DBM, (ii) the equity interests in DBM or (iii) the equity interests in a subsidiary of the Partnership that owns a majority of the outstanding equity interests in DBM. As of June 30, 2015, no such proceeds had been received and no Class C units had been redeemed.

The Class C units were issued at a discount to the then-current market price of the common units into which they are convertible. This discount, totaling $34.8 million, represents a beneficial conversion feature and at December 31, 2014, was reflected as an increase in common unitholders' capital and a decrease in Class C unitholder capital to reflect the fair value of the Class C units at issuance. The beneficial conversion feature is considered a non-cash distribution that will be recognized from the date of issuance through the date of conversion, resulting in an increase in Class C unitholder capital and a decrease in common unitholders' capital. The Partnership is amortizing the beneficial conversion feature assuming a conversion date of December 31, 2017, using the effective yield method. The impact of the beneficial conversion feature is also included in the calculation of earnings per unit.

4. EQUITY AND PARTNERS' CAPITAL (RESTATED) (CONTINUED)

Common, Class C and general partner units. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."
The following table summarizes the common, Class C and general partner units issued during the six months ended June 30, 2015:

	Common Units	Class C Units	General Partner Units	Total
Balance at December 31, 2014	127,695,130	10,913,853	2,583,068	141,192,051
PIK Class C units	—	163,941	—	163,941
Long-Term Incentive Plan award vestings	5,991	—	—	5,991
$500.0 million COP	873,525	—	—	873,525
Balance at June 30, 2015	128,574,646	11,077,794	2,583,068	142,235,508

Holdings of Partnership equity. As of June 30, 2015, WGP held 49,296,205 common units, representing a 34.7% 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 1.8% general partner interest in the Partnership, and 100% of the Partnership's IDRs. As of June 30, 2015, other subsidiaries of Anadarko held 757,619 common units and 11,077,794 Class C units, representing an aggregate 8.3% limited partner interest in the Partnership. As of June 30, 2015, the public held 78,520,822 common units, representing a 55.2% limited partner interest in the Partnership.

Net income (loss) per unit for common units. The Partnership's net income (loss) earned on and subsequent to the date of the acquisition of the Partnership assets is allocated to the general partner and the limited partners, including any Class C unitholders, in accordance with their respective weighted-average ownership percentages and, when applicable, giving effect to incentive distributions allocable to the general partner. The Partnership's net income (loss) allocable to the limited partners is net of amortization of the beneficial conversion feature related to the Class C units (see Class C units above) and is allocated between the common and Class C unitholders by applying the provisions of the partnership agreement that govern actual cash distributions and capital account allocations, as if all earnings for the period had been distributed. Net income (loss) attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners for purposes of calculating net income (loss) per common unit.
Basic net income (loss) per common unit is calculated by dividing the limited partners' interest in net income (loss) attributable to common unitholders by the weighted-average number of common units outstanding during the period. The common units issued in connection with acquisitions and equity offerings are included on a weighted-average basis for periods they were outstanding. Because the Class C units participate in distributions with common units according to a predetermined formula (see Note 3), they are considered a participating security and are included in the computation of earnings per unit pursuant to the two-class method. The Class C unit participation right results in a non-contingent transfer of value each time the Partnership declares a distribution. Diluted net income (loss) per common unit is calculated by dividing the sum of (i) the limited partners' interest in net income (loss) attributable to common units, and (ii) the limited partners' interest in net income (loss) allocable to the Class C units as a participating security, by the sum of the weighted-average number of common units outstanding plus the dilutive effect of outstanding Class C units.

WESTERN GAS PARTNERS, LP
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4. EQUITY AND PARTNERS' CAPITAL (RESTATED) (CONTINUED)

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

thousands except per-unit amounts	Three Months Ended June 30, 2015 (Restated)	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015 (Restated)	Six Months Ended June 30, 2014
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Pre-acquisition net (income) loss allocated to Anadarko	—	(4,135)	(1,742)	(6,800)
General partner interest in net (income) loss	(45,971)	(28,047)	(83,148)	(52,881)
Limited partners' interest in net income (loss)	67,653	66,985	(151,056)	130,542
Net income (loss) allocable to common units [1]	59,119	66,985	(146,139)	130,542
Net income (loss) allocable to Class C units [1]	8,534	—	(4,917)	—
Limited partners' interest in net income (loss)	$67,653	$66,985	$(151,056)	$130,542
Net income (loss) per unit				
Common units - basic	$0.46	$0.57	$(1.14)	$1.11
Common units – diluted [2]	0.46	0.57	(1.14)	1.11
Weighted-average units outstanding				
Common units – basic	128,481	118,177	128,111	117,948
Class C units [2]	11,023	—	10,981	—
Common units – diluted	139,504	118,177	139,092	117,948

(1) Adjusted to reflect amortization for the beneficial conversion feature. See Class C units above for a discussion of the Class C units.
(2) Inclusion of Class C units in the calculation would have had an anti-dilutive effect.

5. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from services provided to Anadarko as well as from the sale of residue, drip condensate and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operation and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership's general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership's omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 2 for further information related to contributions of assets to the Partnership by Anadarko.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition of the Partnership assets, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. The outstanding affiliate balances were entirely settled through an adjustment to net investment by Anadarko in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of Partnership assets from Anadarko, transactions related to such assets are cash-settled directly with third parties and with Anadarko affiliates. Chipeta cash settles its transactions directly with third parties and

Anadarko, as well as with the other subsidiaries of the Partnership.

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Note receivable from and Deferred purchase price obligation - Anadarko. Concurrently with the closing of the Partnership’s May 2008 initial public offering, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The fair value of the note receivable from Anadarko was $304.5 million and $317.8 million at June 30, 2015, and December 31, 2014, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments. Accordingly, the fair value of the note receivable from Anadarko is measured using Level 2 inputs.
The consideration to be paid by the Partnership for the March 2015 acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. See Note 2 and Note 9.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a substantial majority of the commodity price volatility that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs. Notional volumes for each of the commodity price swap agreements are not specifically defined. Instead, the commodity price swap agreements apply to the actual volume of natural gas, condensate and NGLs purchased and sold at the Hugoton system, the MGR assets and the DJ Basin complex, with various expiration dates through December 2016. On December 31, 2014, the Partnership’s commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex (excluding the Granger straddle plant) expired without renewal. The commodity price swap agreements do not satisfy the definition of a derivative financial instrument and, therefore, are not required to be measured at fair value.
Below is a summary of the fixed price ranges on all of the Partnership’s outstanding commodity price swap agreements as of June 30, 2015:

per barrel except natural gas	2015			2016
Ethane	$18.41	–	23.41	$23.11
Propane	47.08	–	52.99	52.90
Isobutane	62.09	–	74.02	73.89
Normal butane	54.62	–	65.04	64.93
Natural gasoline	72.88	–	81.82	81.68
Condensate	76.47	–	81.82	81.68
Natural gas (per MMBtu)	4.66	–	5.96	4.87

The following table summarizes gains and losses upon settlement of commodity price swap agreements:

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2015	2014	2015	2014
Gains (losses) on commodity price swap agreements related to sales: (1)				
Natural gas sales	$22,344	$2,013	$33,326	$(1,654)
Natural gas liquids sales	38,297	34,554	82,729	44,009
Total	60,641	36,567	116,055	42,355
Losses on commodity price swap agreements related to purchases (2)	(41,720)	(18,529)	(75,899)	(18,548)
Net gains (losses) on commodity price swap agreements	$18,921	$18,038	$40,156	$23,807

(1)

Reported in affiliate natural gas, natural gas liquids and drip condensate sales in the consolidated statements of income in the period in which the related sale is recorded.

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

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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

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

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

Revenues or costs attributable to volumes settled during the respective extension period, at the applicable market price in the above table, will be recognized in the consolidated statements of income. The Partnership will also record a capital contribution from Anadarko in the Partnership’s consolidated statement of equity and partners’ capital for the amount by which the swap price exceeds the applicable market price in the above table.

Gas gathering and processing agreements. The Partnership has significant gas gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The Partnership’s gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 47% for the three and six months ended June 30, 2015, and 50% and 49% for the three and six months ended June 30, 2014, respectively. The Partnership’s processing throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 52% for the three and six months ended June 30, 2015, and 58% for the three and six months ended June 30, 2014.

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

WES LTIP. The general partner awards phantom units under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (“WES LTIP”) primarily to its independent directors, but also from time to time to its executive officers and Anadarko employees performing services for the Partnership. The phantom units awarded to the independent directors vest one year from the grant date, while all other awards are subject to graded vesting over a three-year service period. Compensation expense is recognized over the vesting period and was $0.1 million and $0.2 million for the three and six months ended June 30, 2015, respectively, and $0.2 million and $0.3 million for the three and six months ended June 30, 2014, respectively.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

WGP LTIP and Anadarko Incentive Plans. General and administrative expenses included $1.0 million and $2.0 million for the three and six months ended June 30, 2015, respectively, and $0.9 million and $1.8 million for the three and six months ended June 30, 2014, respectively, of equity-based compensation expense, allocated to the Partnership by Anadarko, for awards granted to the executive officers of the general partner and other employees under the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan ("WGP LTIP") and the Anadarko Petroleum Corporation 2008 and 2012 Omnibus Incentive Compensation Plans (collectively referred to as the "Anadarko Incentive Plans"). Of this amount, $1.7 million is reflected as a contribution to partners' capital in the Partnership's consolidated statement of equity and partners' capital for the six months ended June 30, 2015.

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

	Six Months Ended June 30,			
	2015	2014	2015	2014
thousands	Purchases		Sales	
Cash consideration	$9,968	$4,702	$700	$—
Net carrying value	4,908	4,745	366	—
Partners' capital adjustment	$5,060	$(43)	$334	$—

Summary of affiliate transactions. The following table summarizes affiliate transactions, which include revenue from affiliates, reimbursement of operating expenses and purchases of natural gas:

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2015	2014	2015	2014
Revenues (1)	$271,966	$277,583	$530,281	$499,699
Equity income, net (1)	18,941	13,008	37,161	22,259
Cost of product (1)	53,078	38,666	96,990	58,037
Operation and maintenance (2)	17,496	16,827	32,872	29,378
General and administrative (3)	7,319	6,924	14,885	14,227
Operating expenses	77,893	62,417	144,747	101,642
Interest income (4)	4,225	4,225	8,450	8,450
Interest expense (5)	4,190	—	5,610	—
Distributions to unitholders (6)	76,353	56,325	148,048	108,207

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

(2) Represents expenses incurred on and subsequent to the date of the acquisition of the Partnership assets, as well as expenses incurred by Anadarko on a historical basis related to the Partnership assets prior to the acquisition of such assets.

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

LTIP and Anadarko Incentive Plans within this Note 5).

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

(5) For the three and six months ended June 30, 2015, includes accretion expense recognized on the Deferred purchase price obligation - Anadarko for the acquisition of DBJV (see Note 2 and Note 9).

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

6. PROPERTY, PLANT AND EQUIPMENT (RESTATED)

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

thousands	Estimated Useful Life	June 30, 2015 (Restated)	December 31, 2014
Land	n/a	$3,336	$2,884
Gathering systems	3 to 47 years	5,527,042	4,972,892
Pipelines and equipment	15 to 45 years	136,303	151,107
Assets under construction	n/a	262,334	483,347
Other	3 to 40 years	19,133	16,420
Total property, plant and equipment		5,948,148	5,626,650
Accumulated depreciation		1,426,801	1,055,207
Net property, plant and equipment		$4,521,347	$4,571,443

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.
During the six months ended June 30, 2015, the Partnership recognized impairments of $273.9 million, primarily due to an impairment of $264.4 million at its Red Desert complex. This asset was impaired to its estimated fair value of $23.2 million, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput. Also during this period, the Partnership recognized impairments of $9.5 million, primarily due to the abandonment of compressors at the MIGC system and the DJ Basin complex. See Note 2 for a discussion of the Partnership's assets held for sale as of June 30, 2015.

7. EQUITY INVESTMENTS

The following table presents the activity in the Partnership's equity investments for the six months ended June 30, 2015:

	Equity Investments							
thousands	Fort Union	White Cliffs	Rendezvous	Mont Belvieu JV	TEG	TEP	FRP	Total
Balance at December 31, 2014	$25,933	$44,315	$56,336	$121,337	$16,790	$198,793	$170,988	$634,492
Investment earnings (loss), net of amortization	3,191	7,214	1,001	11,377	231	6,818	7,329	37,161
Contributions	—	4,370	—	(433)	—	1,430	1,403	6,770
Distributions	(3,656)	(6,923)	(1,972)	(12,035)	(436)	(6,944)	(7,068)	(39,034)
Distributions in excess of cumulative earnings (1)	—	(2,026)	(1,863)	(1,025)	(80)	(2,798)	(746)	(8,538)
Balance at June 30, 2015	$25,468	$46,950	$53,502	$119,221	$16,505	$197,299	$171,906	$630,851

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

WESTERN GAS PARTNERS, LP
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8. COMPONENTS OF WORKING CAPITAL (RESTATED)

A summary of other current assets is as follows:

thousands	June 30, 2015	December 31, 2014
Natural gas liquids inventory	$6,447	$5,316
Natural gas imbalance receivables	1,016	415
Prepaid insurance	346	2,443
Other	3,861	1,893
Total other current assets	$11,670	$10,067

A summary of accrued liabilities is as follows:

thousands	June 30, 2015 (Restated)	December 31, 2014
Accrued capital expenditures	$78,086	$128,856
Accrued plant purchases	37,928	14,023
Accrued interest expense	26,071	24,741
Short-term asset retirement obligations	4,450	1,224
Short-term remediation and reclamation obligations	475	475
Income taxes payable	15	207
Other	2,163	1,263
Total accrued liabilities	$149,188	$170,789

9. DEBT AND INTEREST EXPENSE

At June 30, 2015, the Partnership's debt consisted of 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes"), 3.950% Senior Notes due 2025 (the "2025 Notes"), and borrowings on the senior unsecured revolving credit facility ("RCF").
The following table presents the Partnership's outstanding debt as of June 30, 2015, and December 31, 2014:

	June 30, 2015			December 31, 2014		
thousands	Principal	Carrying Value	Fair Value (1)	Principal	Carrying Value	Fair Value (1)
2021 Notes	$500,000	$495,995	$544,930	$500,000	$495,714	$549,530
2022 Notes	670,000	672,752	673,994	670,000	672,930	681,942
2018 Notes	350,000	350,412	352,497	350,000	350,474	352,162
2044 Notes	400,000	393,879	400,692	400,000	393,836	417,619
2025 Notes	500,000	493,985	482,161	—	—	—
RCF	270,000	270,000	270,000	510,000	510,000	510,000
Total long-term debt	$2,690,000	$2,677,023	$2,724,274	$2,430,000	$2,422,954	$2,511,253

(1) Fair value is measured using Level 2 inputs.

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WESTERN GAS PARTNERS, LP
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9. DEBT AND INTEREST EXPENSE (CONTINUED)

Debt activity. The following table presents the debt activity of the Partnership for the six months ended June 30, 2015:

thousands	Carrying Value
Balance at December 31, 2014	$2,422,954
RCF borrowings	280,000
Issuance of 2025 Notes	500,000
Repayments of RCF	(520,000)
Other	(5,931)
Balance at June 30, 2015	$2,677,023

Senior Notes. The 2025 Notes issued in June 2015 were offered at a price to the public of 98.789% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2025 Notes is 4.205%. Interest is paid semi-annually on June 1 and December 1 of each year. Proceeds (net of underwriting discount of $3.3 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the Partnership's RCF.
At June 30, 2015, the Partnership was in compliance with all covenants under the indentures governing its outstanding notes.

Revolving credit facility. The interest rate on the RCF, which matures in February 2019, was 1.49% and 1.46% at June 30, 2015, and June 30, 2014, respectively. The facility fee rate was 0.20% at June 30, 2015, and June 30, 2014. As of June 30, 2015, the Partnership had $270.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $917.2 million available for borrowing under the RCF. At June 30, 2015, the Partnership was in compliance with all covenants under the RCF.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2015	2014	2015	2014
Third parties				
Long-term debt	$24,733	$21,445	$48,075	$37,580
Amortization of debt issuance costs and commitment fees	1,374	1,426	2,666	2,692
Capitalized interest	(2,693)	(2,007)	(5,787)	(5,447)
Total interest expense – third parties	23,414	20,864	44,954	34,825
Affiliates				
Deferred purchase price obligation – Anadarko[(1)]	4,190	—	5,610	—
Total interest expense – affiliates	4,190	—	5,610	—
Interest expense	$27,604	$20,864	$50,564	$34,825

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

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10. COMMITMENTS AND CONTINGENCIES

Litigation and legal proceedings. In March 2011, DCP Midstream, LP ("DCP") filed a lawsuit against Anadarko and others, including a Partnership subsidiary, Kerr-McGee Gathering, LLC, in Weld County District Court (the "Court") in Colorado, alleging that Anadarko diverted gas from DCP's gathering and processing facilities in breach of certain dedication agreements. In addition to various claims against Anadarko, DCP is claiming unjust enrichment and other damages against Kerr-McGee Gathering, LLC, the entity that holds the Wattenberg assets (located in the DJ Basin complex). Anadarko countersued DCP asserting that DCP has not properly allocated values and charges to Anadarko for the gas that DCP gathers and/or processes, and seeks a judgment that DCP has no valid gathering or processing rights to much of the gas production it is claiming, in addition to other claims.

The Court has scheduled this matter for trial in June 2016, and the parties are currently engaged in discovery and motion practice. Management does not believe the outcome of this proceeding will have a material effect on the Partnership's financial condition, results of operations or cash flows. The Partnership intends to vigorously defend this litigation. Furthermore, without regard to the merit of DCP's claims, management believes that the Partnership has adequate contractual indemnities covering the claims against it in this lawsuit.

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

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates. As of June 30, 2015, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $52.3 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to construction of Trains IV and V at the DBM complex and continued expansion at the DJ Basin complex, as well as projects at the Haley system.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting the Partnership's operations, for which Anadarko charges the Partnership rent. The leases for the corporate offices and shared field offices extend through 2017 and 2018, respectively, and the lease for the warehouse extends through February 2017.

Rent expense associated with the office, warehouse and equipment leases was $4.5 million and $8.7 million for the three and six months ended June 30, 2015, respectively, and $2.0 million and $4.3 million for the three and six months ended June 30, 2014, respectively.

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

Western Gas Partners, LP is a growth-oriented master limited partnership (“MLP”) formed by Anadarko Petroleum Corporation in 2007. For purposes of this report, “we,” “us,” “our,” the “Partnership” or “Western Gas Partners” refer to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the “general partner” or “GP”), is owned by Western Gas Equity Partners, LP (“WGP”), a Delaware MLP formed by Anadarko Petroleum Corporation. 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 us and our general partner, and “affiliates” refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”), Enterprise EF78 LLC (the “Mont Belvieu JV”), Texas Express Pipeline LLC (“TEP”), Texas Express Gathering LLC (“TEG”) and Front Range Pipeline LLC (“FRP”). The interests in TEP, TEG and FRP are referred to collectively as the “TEFR Interests.” “Equity investment throughput” refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput.
The “DJ Basin complex” refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014. The “MGR assets” include the Red Desert complex, the Granger straddle plant and the 22% interest in Rendezvous.
The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included under Part I, Item 1 of this quarterly report, as well as our historical consolidated financial statements, and the notes thereto, which are included in Part II, Item 8 of our 2014 Form 10-K as filed with the Securities and Exchange Commission, or “SEC,” on February 26, 2015.

RESTATEMENT AND OTHER ADJUSTMENTS

As discussed in the Explanatory Note and in Note 1—Description of Business and Basis of Presentation (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A, we are restating our unaudited consolidated financial statements and related disclosures as of, and for the three and six months ended, June 30, 2015. The following discussion and analysis of our financial condition and results of operations incorporates the restated amounts and other adjustments. For this reason, the data set forth in this Item 2 may not be comparable to the discussion and data in our Original Filing.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this report, 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," "should" or simil or variations on such expressions. These statements discuss future expectations, contain projections of results of operations or financial condition or include other "forward-looking" information.
Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurance that such expectations will prove to have been correct. These forward-looking statements involve risks and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following:

- our ability to pay distributions to our unitholders;
- our and Anadarko's assumptions about the energy market;
- future throughput, including Anadarko's production, which is gathered or processed by or transported through our assets;
- our operating results;
- competitive conditions;
- technology;
- the availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;
- the supply of, demand for, and the price of, oil, natural gas, NGLs and related products or services;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;
- federal, state and local laws, including those that limit Anadarko and other producers' hydraulic fracturing or other oil and natural gas operations;
- 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;

- changes in Anadarko’s capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use our senior unsecured revolving credit facility (“RCF”);

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- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;
- our ability to repay debt;
- our ability to mitigate exposure to a substantial majority of the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;
- our ability to acquire assets on acceptable terms;
- non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko;
- the timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below, in "Risk Factors" and in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates," included in our 2014 Form 10-K, 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 report 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.

EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to acquire, own, develop and operate midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas, and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of June 30, 2015, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	2	5	2
Natural gas treating facilities	10	5	—	1
Natural gas processing facilities	14	5	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipelines	1	—	—	1

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Significant financial and operational highlights during the six months ended June 30, 2015, included the following:

- We completed the acquisition of Delaware Basin JV Gathering LLC from Anadarko. See Acquisitions and Divestitures below.

- We issued $500.0 million aggregate principal amount of 3.950% Senior Notes due 2025. Net proceeds were used to repay a portion of the amount outstanding under our RCF. See Liquidity and Capital Resources within this Item 2 for additional information.

- In June 2015, we completed the construction and commenced operations of Lancaster Train II, a 300 MMcf/d processing plant located in the DJ Basin complex in Northeast Colorado.

- We issued 873,525 common units to the public under our $500.0 million Continuous Offering Program (see Equity Offerings below), generating net proceeds of $57.4 million. Net proceeds were used for general partnership purposes, including funding capital expenditures.

- We raised our distribution to $0.750 per unit for the second quarter of 2015, representing a 3% increase over the distribution for the first quarter of 2015 and a 15% increase over the distribution for the second quarter of 2014.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 4,083 MMcf/d and 4,000 MMcf/d for the three and six months ended June 30, 2015, respectively, representing a 13% increase compared to the same periods in 2014.

- Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $0.69 per Mcf and $0.68 per Mcf for the three and six months ended June 30, 2015, respectively, representing a 1% and 5% increase, respectively, compared to the same periods in 2014.

- Adjusted gross margin for crude/NGL assets (as defined under the caption Key Performance Metrics within this Item 2) averaged $1.80 per Bbl and $1.76 per Bbl for the three and six months ended June 30, 2015, respectively, representing a 13% and 4% decrease, respectively, compared to the same periods in 2014.

- On June 25, 2015, we extended our commodity price swap agreements with Anadarko for the DJ Basin complex from July 1, 2015, through December 31, 2015, and for the Hugoton system from October 1, 2015, through December 31, 2015. The prices set forth in the extended swaps are more favorable than prevailing market prices on the date the extended commodity price swap agreements were executed. There can be no assurance that these commodity price swap agreements will be renewed or extended beyond December 31, 2015, on similar terms or at all. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for further information.

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ACQUISITIONS AND DIVESTITURES

Acquisitions. The following table presents our acquisitions during 2015 and 2014, and identifies the funding sources for such acquisitions. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired		Deferred Purchase Price Obligation - Anadarko	Borrowings	Cash On Hand	Common Units Issued to Anadarko	Class C Units Issued to Anadarko
TEFR Interests (1)	03/03/2014	Various (1)		$—	$350,000	$6,250	308,490	—
DBM (2)	11/25/2014	100	%	—	475,000	298,327	—	10,913,853
DBJV system (3)	03/02/2015	50	%	174,276	—	—	—	—

(1) We acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP from Anadarko. These assets gather and transport NGLs primarily from the Anadarko and Denver-Julesburg ("DJ") Basins. TEG consists of two NGL gathering systems that link natural gas processing plants to TEP. TEP is an NGL pipeline that originates in Skellytown, Texas and extends approximately 593 miles to Mont Belvieu, Texas. FRP is a 435-mile NGL pipeline that extends from Weld County, Colorado to Skellytown, Texas. The interests in these entities are accounted for under the equity method of accounting. In connection with the issuance of the common units, our general partner purchased 6,296 general partner units in exchange for the general partner's proportionate capital contribution of $0.4 million.

(2) We acquired Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM"). The assets acquired include cryogenic processing plants, a gas gathering system, and related facilities and equipment, which are collectively referred to as the "DBM complex" and serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for further information, including the preliminary allocation of the purchase price.

(3) We acquired Anadarko's interest in Delaware Basin JV Gathering LLC ("DBJV"), which owns a 50% interest in a gathering system and related facilities (the "DBJV system"). The DBJV system is located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties, Texas. We will make a cash payment on March 31, 2020, to Anadarko as consideration for the acquisition of DBJV. We currently estimate the future payment will be $282.8 million, the net present value of which was $174.3 million as of the acquisition date. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Assets held for sale - Dew and Pinnacle systems. During the second quarter of 2015, the Dew and Pinnacle systems in East Texas satisfied criteria to be considered held for sale. At June 30, 2015, our consolidated balance sheet included current assets of $2.2 million, long-term assets of $71.9 million, current liabilities of $4.2 million and long-term liabilities of $3.0 million associated with assets held for sale. The sale of these assets is expected to close on July 31, 2015.

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Presentation of Partnership assets. The term “Partnership assets” refers to the assets owned and interests accounted for under the equity method (see Note 7—Equity Investments in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A) by us as of June 30, 2015. Because Anadarko controls us through its ownership and control of WGP, which owns the entire interest in our general partner, each of our acquisitions of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko’s historic carrying value, which did not correlate to the total acquisition price paid by us (see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control.

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

EQUITY OFFERINGS

Equity offerings. We completed the following public offerings of our common units during 2015 and 2014, including through our Continuous Offering Programs (“COP”):

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued (1)	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
2014					
$125.0 million COP (2)	1,133,384	23,132	$73.48	$1,738	$83,245
November 2014 equity offering (3)	8,620,153	153,061	70.85	18,615	602,967
2015					
$500.0 million COP (4)	873,525	—	$66.61	$782	$57,408

(1) Represents general partner units issued to the general partner in exchange for the general partner’s proportionate capital contribution.

(2) Represents common and general partner units issued during the year ended December 31, 2014, pursuant to our registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the “$125.0 million COP”). Gross proceeds generated (including the general partner’s proportionate capital contributions) during the year ended December 31, 2014, were $85.0 million. The price per unit in the table above represents an average price for all issuances under the $125.0 million COP during the year ended December 31, 2014. As of December 31, 2014, we had used all the capacity to issue common units under this registration statement.

(3) Includes the issuance of 1,120,153 common units pursuant to the partial exercise of the underwriters’ over-allotment option, the net proceeds from which were $77.0 million. Beginning with this partial exercise, our general partner elected not to make a corresponding capital contribution to maintain its 2.0% interest in us.

(4) Represents common units issued during the six months ended June 30, 2015, pursuant to our registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of common units (the “$500.0 million COP”). Gross proceeds generated during the three and six months ended June 30, 2015, were $26.7 million and $58.2 million, respectively. Commissions paid during the three and six months ended June 30, 2015, were $0.3 million and $0.6 million, respectively. The price per unit in the table above represents an average price for all issuances under the $500.0 million COP during the six months ended June 30, 2015.

Other equity offerings. In November 2014, we issued 10,913,853 Class C units to a subsidiary of Anadarko at an implied price of $68.72 per unit, generating proceeds of $750.0 million, all of which was used to fund a portion of the acquisition of DBM. See Note 2—Acquisitions and Divestitures and Note 4—Equity and Partners' Capital (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

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RESULTS OF OPERATIONS

OPERATING RESULTS

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

thousands	Three Months Ended June 30, 2015 (Restated)	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015 (Restated)	Six Months Ended June 30, 2014
Gathering, processing and transportation of natural gas and natural gas liquids	$241,455	$185,922	$463,110	$346,935
Natural gas, natural gas liquids and drip condensate sales	174,202	169,403	339,874	308,068
Other	915	2,056	1,997	3,627
Total revenues [1]	416,572	357,381	804,981	658,630
Equity income, net	18,941	13,008	37,161	22,259
Total operating expenses [1]	297,475	248,824	858,588	453,532
Operating income (loss)	138,038	121,565	(16,446)	227,357
Interest income – affiliates	4,225	4,225	8,450	8,450
Interest expense	(27,604)	(20,864)	(50,564)	(34,825)
Other income (expense), net	71	214	142	691
Income (loss) before income taxes	114,730	105,140	(58,418)	201,673
Income tax (benefit) expense	(1,710)	2,523	1,706	4,308
Net income (loss)	116,440	102,617	(60,124)	197,365
Net income attributable to noncontrolling interest	2,816	3,450	6,042	7,142
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Key performance metrics [2]				
Adjusted gross margin attributable to Western Gas Partners, LP	$277,360	$244,420	$531,396	$450,980
Adjusted EBITDA attributable to Western Gas Partners, LP	205,452	175,289	386,352	323,395
Distributable cash flow	173,308	143,794	321,305	268,920

(1) Revenues include amounts earned from services provided to our affiliates, as well as from the sale of residue, drip condensate and NGLs to our affiliates. Operating expenses include amounts charged by our affiliates for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

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

For purposes of the following discussion, any increases or decreases “for the three months ended June 30, 2015” refer to the comparison of the three months ended June 30, 2015, to the three months ended June 30, 2014; any increases or decreases “for the six months ended June 30, 2015” refer to the comparison of the six months ended June 30, 2015, to the six months ended June 30, 2014; and any increases or decreases “for the three and six months ended June 30, 2015” refer to the comparison of these 2015 periods to the corresponding three and six month periods ended June 30, 2014.

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Throughput

MMcf/d (except throughput measured in barrels)	Three Months Ended June 30, 2015	2014	Inc/ (Dec)	Six Months Ended June 30, 2015	2014	Inc/ (Dec)
Throughput for natural gas assets						
Gathering, treating and transportation	1,605	1,673	(4)%	1,630	1,660	(2)%
Processing	2,465	1,971	25 %	2,362	1,885	25 %
Equity investment [1]	172	153	12 %	169	170	(1)%
Total throughput for natural gas assets	4,242	3,797	12 %	4,161	3,715	12 %
Throughput attributable to noncontrolling interest for natural gas assets	159	171	(7)%	161	172	(6)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets [2]	4,083	3,626	13 %	4,000	3,543	13 %
Total throughput (MBbls/d) for crude/NGL assets [3]	134	115	17 %	133	97	37 %

(1) Represents our 14.81% share of average Fort Union and our 22% share of average Rendezvous throughput. Excludes equity investment throughput measured in barrels (captured in "Total throughput (MBbls/d) for crude/NGL assets" as noted below).

(2) Includes affiliate, third-party and equity investment throughput (as equity investment throughput is defined in the above footnote), excluding the noncontrolling interest owner's proportionate share of throughput.

(3) Represents total throughput measured in barrels, consisting of throughput from our Chipeta NGL pipeline, our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput, and our 33.33% share of average FRP throughput.

Gathering, treating and transportation throughput decreased by 68 MMcf/d and 30 MMcf/d for the three and six months ended June 30, 2015, respectively, primarily due to production declines in the areas around the Anadarko-Operated Marcellus Interest systems and the Bison facility, and for the three months ended June 30, 2015, decreases at the Non-Operated Marcellus Interest systems as a result of a third-party curtailment of production. These decreases were partially offset by higher volumes at the DJ Basin complex due to increased production in the area.
Processing throughput increased by 494 MMcf/d and 477 MMcf/d for the three and six months ended June 30, 2015, respectively, primarily due to increased production in areas around the DJ Basin complex and the DBJV system, as well as the acquisition of DBM in November 2014, partially offset by decreased throughput at the Chipeta complex.
Equity investment throughput increased by 19 MMcf/d for the three months ended June 30, 2015, primarily due to volumes being diverted from the third-party Bison pipeline to the Fort Union system, as well as increased throughput at the Rendezvous system.
Throughput for crude/NGL assets measured in barrels increased by 19 MBbls/d and 36 MBbls/d for the three and six months ended June 30, 2015, respectively, due to an increase in volumes from FRP and TEP, and the third quarter 2014 in-service date of a White Cliffs pipeline expansion. The increase during the three months ended June 30, 2015, was partially offset by a decrease at the Mont Belvieu JV due to lower inlet throughput.

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Gathering, Processing and Transportation of Natural Gas and Natural Gas Liquids

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages	2015	2014	Inc/ (Dec)	2015	2014	Inc/ (Dec)
Gathering, processing and transportation of natural gas and natural gas liquids	$241,455	$185,922	30 %	$463,110	$346,935	33 %

Revenues from gathering, processing and transportation of natural gas and natural gas liquids increased by $55.5 million and $116.2 million for the three and six months ended June 30, 2015, respectively, primarily due to increases of (i) $41.4 million and $89.6 million, respectively, at the DJ Basin complex resulting from increased throughput, a higher gathering fee, and the introduction of a condensate handling fee in the first quarter of 2015, (ii) $15.8 million and $26.0 million, respectively, due to the acquisition of DBM in November 2014, (iii) $3.1 million and $6.0 million, respectively, at the Brasada complex due to increased throughput and a higher processing fee, as well as revenues from treating services beginning in the first quarter of 2015, and (iv) $3.0 million and $5.8 million, respectively, at the Hilight system due to higher throughput. These increases were partially offset by decreases of $5.2 million and $10.2 million, respectively, at the Non-Operated Marcellus Interest systems due to a decrease in average gathering rate and a third-party curtailment of production.

Natural Gas, Natural Gas Liquids and Drip Condensate Sales

	Three Months Ended June 30,			Six Months Ended June 30,		
thousands except percentages and per-unit amounts	2015	2014	Inc/ (Dec)	2015	2014	Inc/ (Dec)
Natural gas sales	$71,463	$38,877	84 %	$133,654	$70,786	89 %
Natural gas liquids sales	92,317	118,647	(22)%	183,253	214,461	(15)%
Drip condensate sales	10,422	11,879	(12)%	22,967	22,821	1 %
Total	$174,202	$169,403	3 %	$339,874	$308,068	10 %
Average price per unit:						
Natural gas (per Mcf)	$3.68	$4.33	(15)%	$3.64	$4.30	(15)%
Natural gas liquids (per Bbl)	20.87	47.90	(56)%	23.10	46.45	(50)%
Drip condensate (per Bbl)	35.41	89.57	(60)%	44.53	83.48	(47)%

For the three and six months ended June 30, 2015, average natural gas, NGL and drip condensate prices included the effects of commodity price swap agreements attributable to sales for the Hugoton system, the MGR assets and the DJ Basin complex. For the three and six months ended June 30, 2014, average natural gas, NGL and drip condensate prices included the effects of commodity price swap agreements attributable to sales for the Hilight, Hugoton and Newcastle systems, the DJ Basin and Granger complexes, and the MGR assets. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex (excluding the Granger straddle plant) expired without renewal. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and drip condensate sales increased by $4.8 million for the three months ended June 30, 2015, consisting of a $32.6 million increase in natural gas sales, partially offset by decreases of $26.3 million in NGLs sales and $1.5 million in drip condensate sales.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and drip condensate sales increased by $31.8 million for the six months ended June 30, 2015, consisting of increases of $62.9 million in natural gas sales and $0.1 million in drip condensate sales, partially offset by a decrease of $31.2 million in NGLs sales.

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The growth in natural gas sales for the three and six months ended June 30, 2015, was primarily due to increases of (i) $20.4 million and $44.7 million, respectively, due to the acquisition of DBM in November 2014 and (ii) $18.5 million and $26.0 million, respectively, at the DJ Basin complex due to an increase in volumes sold. These increases were partially offset by decreases of $4.4 million and $5.3 million for the three and six months ended June 30, 2015, respectively, at the Hilight system due to a decrease in average price as a result of the expiration of swap agreements in December 2014. In addition, the increase in natural gas sales for the three months ended June 30, 2015, was partially offset by a decrease of $1.2 million at the MGR assets due to a decrease in volumes sold.

The decline in NGLs sales for the three and six months ended June 30, 2015, was primarily due to decreases of (i) $17.8 million and $33.9 million, respectively, at the Granger complex due to a decrease in average price as a result of the expiration of swap agreements in December 2014, as well as a decrease in volumes sold, (ii) $11.8 million and $16.7 million, respectively, at the Hilight system due to a decrease in average price as a result of the expiration of swap agreements in December 2014, (iii) $18.4 million and $15.2 million, respectively, at the DJ Basin complex due to a decrease in volumes sold, (iv) $4.3 million and $9.1 million, respectively, at the Chipeta complex due to a decrease in average price, and (v) $4.4 million and $6.9 million, respectively, at the MGR assets due to a decrease in volumes sold. These decreases were partially offset by increases of $31.0 million and $51.8 million for the three and six months ended June 30, 2015, respectively, due to the acquisition of DBM in November 2014.

The decline in drip condensate sales for the three months ended June 30, 2015, was primarily due to a decrease of $1.3 million at the DJ Basin complex as a result of fewer volumes sold.

Equity Income, Net

thousands except percentages	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Inc/ (Dec)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Inc/ (Dec)
Equity income, net	$18,941	$13,008	46 %	$37,161	$22,259	67 %

For the three and six months ended June 30, 2015, equity income, net increased by $5.9 million and $14.9 million, respectively, primarily due to a full second quarter 2015 of equity income recognized from the TEFR Interests and the third quarter 2014 in-service date of a White Cliffs pipeline expansion, partially offset by a decrease in equity income from the Mont Belvieu JV.

Cost of Product and Operation and Maintenance Expenses

thousands except percentages	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Inc/ (Dec)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Inc/ (Dec)
NGL purchases	$73,362	$55,535	32 %	$137,560	$103,416	33 %
Residue purchases	66,878	52,506	27 %	135,222	90,690	49 %
Other	6,992	14,277	(51)%	13,875	23,603	(41)%
Cost of product	147,232	122,318	20 %	286,657	217,709	32 %
Operation and maintenance	70,048	65,440	7 %	138,007	116,534	18 %
Total cost of product and operation and maintenance expenses	$217,280	$187,758	16 %	$424,664	$334,243	27 %

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Cost of product expense for the three and six months ended June 30, 2015, included the effects of commodity price swap agreements attributable to purchases for the Hugoton system, the MGR assets and the DJ Basin complex. Cost of product expense for the three and six months ended June 30, 2014, included the effects of commodity price swap agreements attributable to purchases for the Hilight, Hugoton and Newcastle systems, the DJ Basin and Granger complexes and the MGR assets. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex (excluding the Granger straddle plant) expired without renewal. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Including the effects of commodity price swap agreements on purchases, cost of product expense for the three months ended June 30, 2015, increased by $24.9 million, consisting of $17.8 million in NGL purchases and $14.4 million in residue purchases, partially offset by a decrease of $7.3 million in other.

The increase in NGL purchases for the three months ended June 30, 2015, was primarily due to increases of (i) $29.0 million due to the acquisition of DBM in November 2014 and (ii) $3.5 million at the DJ Basin complex due to an increase in average swap price and volume. These increases were partially offset by decreases of (i) $10.5 million at the Hilight system and the Granger complex due to decreases in average prices as a result of the expiration of swap agreements in December 2014 and (ii) $3.1 million at the Chipeta complex due to a decrease in average price.

The increase in residue purchases for the three months ended June 30, 2015, was primarily due to increases of (i) $19.8 million due to the acquisition of DBM in November 2014 and (ii) $6.5 million at the DJ Basin complex due to an increase in average swap price and volume. These increases were partially offset by decreases of (i) $8.2 million at the Granger complex and the Hilight system due to decreases in average prices as a result of the expiration of swap agreements in December 2014 and (ii) $2.0 million at the Granger straddle plant due to a decrease in volume.

The decrease in other items for the three months ended June 30, 2015, was primarily due to changes in imbalance positions at the DJ Basin complex.

The $4.6 million increase in operation and maintenance expense for three months ended June 30, 2015, was primarily due to an increase of $8.3 million due to the acquisition of DBM in November 2014, partially offset by a decrease of $3.2 million at the Non-Operated Marcellus Interest systems due to a decrease in third party operating expense.

Including the effects of commodity price swap agreements on purchases, cost of product expense for the six months ended June 30, 2015, increased by $68.9 million, consisting of $34.1 million in NGL purchases and $44.5 million in residue purchases, partially offset by a decrease of $9.7 million in other.

The increase in NGL purchases for the six months ended June 30, 2015, was primarily due to an increase of $48.9 million due to the acquisition of DBM in November 2014 partially offset by decreases of (i) $14.1 million at the Hilight system and the Granger complex due to decreases in average prices as a result of the expiration of swap agreements in December 2014 and (ii) $6.6 million at the Chipeta complex due to a decrease in average price.

The increase in residue purchases for the six months ended June 30, 2015, was primarily due to increases of (i) $43.5 million due to the acquisition of DBM in November 2014 and (ii) $19.7 million at the DJ Basin complex due to an increase in average swap price and volume. These increases were partially offset by decreases of (i) $14.3 million at the Granger complex and the Hilight system due to decreases in average prices as a result of the expiration of swap agreements in December 2014 and (ii) $2.5 million at the Granger straddle plant due to a decrease in volume.

The decrease in other items for the six months ended June 30, 2015, was primarily due to changes in imbalance positions at the DJ Basin complex.

The $21.5 million increase in operation and maintenance expense for the six months ended June 30, 2015, was primarily due to an increase of $14.6 million due to the acquisition of DBM in November 2014, partially offset by a decrease of $3.2 million at the Non-Operated Marcellus Interest systems due to a decrease in third party operating expense.

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

thousands except percentages	Three Months Ended June 30, 2015 (Restated)	2014	Inc/ (Dec)		Six Months Ended June 30, 2015 (Restated)	2014	Inc/ (Dec)	
General and administrative	$8,667	$8,445	3	%	$19,179	$17,349	11	%
Property and other taxes	8,775	7,316	20	%	17,298	14,550	19	%
Depreciation and amortization	61,485	44,962	37	%	123,555	85,857	44	%
Impairments	1,268	343	NM		273,892	1,533	NM	
Total general and administrative, depreciation and amortization, impairments and other expenses	$80,195	$61,066	31	%	$433,924	$119,289	NM	

NM-Not meaningful

General and administrative expenses increased by $0.2 million for the three months ended June 30, 2015, primarily due to increases of (i) $0.3 million in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement, (ii) $0.1 million in legal fees, and (iii) $0.1 million in equity-based compensation, which were partially offset by a decrease of $0.3 million in consulting and audit fees.

General and administrative expenses increased by $1.8 million for the six months ended June 30, 2015, primarily due to increases of (i) $1.3 million in consulting, audit fees and other and (ii) $0.5 million in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement.

Property and other taxes increased by $1.5 million and $2.7 million for the three and six months ended June 30, 2015, respectively, primarily due to ad valorem tax increases of $1.3 million and $2.7 million, respectively, at the DJ Basin complex and due to the acquisition of DBM in November 2014.

See Note 1—Description of Business and Basis of Presentation (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for a description of depreciation and amortization and impairment amounts restated.

Depreciation and amortization increased by $16.5 million for the three months ended June 30, 2015, primarily due to depreciation expense increases of (i) $11.9 million due to the acquisition of DBM in November 2014 and (ii) $4.6 million associated with the completion of numerous compression projects and the start-up of Lancaster Train I in April 2014 at the DJ Basin complex. These increases were partially offset by a decrease of $3.3 million driven by the impairment at the Red Desert complex in March 2015.

Depreciation and amortization increased by $37.7 million for the six months ended June 30, 2015, primarily due to depreciation expense increases of (i) $23.6 million due to the acquisition of DBM in November 2014, (ii) $10.7 million associated with the completion of numerous compression projects and the start-up of Lancaster Train I in April 2014 at the DJ Basin complex, and (iii) $2.8 million at the DBJV and Hilight systems. These increases were partially offset by a decrease of $3.3 million driven by the impairment at the Red Desert complex in March 2015.

Impairment expense increased by $0.9 million for the three months ended June 30, 2015, driven by the cancellation of projects at the DBJV system and the Red Desert and DJ Basin complexes.

Impairment expense increased by $272.4 million for the six months ended June 30, 2015, primarily due to an impairment of $264.4 million at the Red Desert complex. This asset was impaired to its estimated fair value of $23.2 million, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput. Also during this period, impairment expense increased by $8.0 million, primarily due to the abandonment of compressors at the MIGC system and the DJ Basin complex and the cancellation of projects at the DBJV system and the Brasada and Red Desert complexes.

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Interest Income – Affiliates and Interest Expense

thousands except percentages	Three Months Ended June 30, 2015	2014	Inc/ (Dec)	Six Months Ended June 30, 2015	2014	Inc/ (Dec)
Note receivable – Anadarko	$4,225	$4,225	— %	$8,450	$8,450	— %
Interest income – affiliates	$4,225	$4,225	— %	$8,450	$8,450	— %
Third parties						
Long-term debt	$(24,733)	$(21,445)	15 %	$(48,075)	$(37,580)	28 %
Amortization of debt issuance costs and commitment fees	(1,374)	(1,426)	(4)%	(2,666)	(2,692)	(1)%
Capitalized interest	2,693	2,007	34 %	5,787	5,447	6 %
Affiliates						
Deferred purchase price obligation – Anadarko [(1)]	(4,190)	—	— %	(5,610)	—	— %
Interest expense	$(27,604)	$(20,864)	32 %	$(50,564)	$(34,825)	45 %

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

Interest expense increased by $6.7 million and $15.7 million for the three and six months ended June 30, 2015, respectively, primarily due to (i) additional interest incurred on the RCF of $1.8 million and $3.7 million, respectively, as a result of higher average borrowings outstanding, and (ii) $1.5 million in interest incurred on the 3.950% Senior Notes due 2025 issued in June 2015. In addition, during the six months ended June 30, 2015, interest expense increased due to additional interest of $4.8 million incurred on the 5.450% Senior Notes due 2044 and $0.6 million incurred on the additional 2.600% Senior Notes due 2018, both issued in March 2014. Capitalized interest increased by $0.7 million and $0.3 million for the three and six months ended June 30, 2015, respectively, due to the construction of Lancaster Train II (part of the DJ Basin complex) and Train IV at the DBM complex (acquired in November 2014), partially offset by a decrease due to the completion of Lancaster Train I (part of the DJ Basin complex) in April 2014. See Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Income Tax (Benefit) Expense

thousands except percentages	Three Months Ended June 30, 2015 (Restated)	2014	Inc/ (Dec)	Six Months Ended June 30, 2015 (Restated)	2014	Inc/ (Dec)
Income (loss) before income taxes	$114,730	$105,140	9 %	$(58,418)	$201,673	(129)%
Income tax (benefit) expense	(1,710)	2,523	(168)%	1,706	4,308	(60)%
Effective tax rate	NM	2 %		NM	2 %	

NM-Not meaningful

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

Texas House Bill 32, signed into law in June 2015, reduced the Texas margin tax rates by 0.25%. The law is effective January 1, 2016. We are required to include the impact of the law change on our deferred state income taxes in the period enacted. The adjustment, a reduction in deferred state income taxes in the amount of $2.2 million, was included in the income tax (benefit) expense for the three and six months ended June 30, 2015.

Income attributable to (a) the DBJV system prior to and including February 2015 and (b) the TEFR Interests prior to and including February 2014 was subject to federal and state income tax. Income earned on the DBJV system and the TEFR Interests for periods subsequent to February 2015 and February 2014, respectively, was only subject to Texas margin tax on income apportionable to Texas.

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KEY PERFORMANCE METRICS

thousands except percentages and per-unit amounts	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Inc/ (Dec)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014	Inc/ (Dec)
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (1)	$255,342	$222,913	15 %	$489,194	$418,684	17 %
Adjusted gross margin for crude/NGL assets (2)	22,018	21,507	2 %	42,202	32,296	31 %
Adjusted gross margin attributable to Western Gas Partners, LP (3)	277,360	244,420	13 %	531,396	450,980	18 %
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (4)	0.69	0.68	1 %	0.68	0.65	5 %
Adjusted gross margin per Bbl for crude/NGL assets (5)	1.80	2.06	(13)%	1.76	1.84	(4)%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	205,452	175,289	17 %	386,352	323,395	19 %
Distributable cash flow (3)	173,308	143,794	21 %	321,305	268,920	19 %

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

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

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

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

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

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

Adjusted gross margin increased by $32.9 million and $80.4 million for the three and six months ended June 30, 2015, respectively, primarily due to the start-up of Lancaster Train I (part of the DJ Basin complex) in April 2014 and the acquisition of DBM in November 2014, partially offset by margin decreases at the Granger complex due to lower average pricing and at the Non-Operated Marcellus Interest systems due to a decrease in the average gathering rate and a third-party curtailment of production.

To facilitate investor and industry analyst comparisons between us and our peers, we also disclose Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets and Adjusted gross margin per Bbl for crude/NGL assets. Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.01 and $0.03 for the three and six months ended June 30, 2015, primarily due to the start-up of Lancaster Train I (part of the DJ Basin complex) in April 2014 and the acquisition of DBM in November 2014, partially offset by lower margins at the Non-Operated Marcellus Interest systems due to a decrease in the average gathering rate. Adjusted gross margin per Bbl for crude/NGL assets decreased by $0.26 and $0.08 for the three and six months ended June 30, 2015, respectively, primarily due to lower distributions received from the Mont Belvieu JV.

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Adjusted EBITDA attributable to Western Gas Partners, LP. We define Adjusted EBITDA attributable to Western Gas Partners, LP ("Adjusted EBITDA") as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation and amortization, impairments, and other expense, less gains on divestitures, income from equity investments, interest income, income tax benefit and other income. We believe that the presentation of Adjusted EBITDA provides information useful to investors in assessing our financial condition and results of operations and that Adjusted EBITDA is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures and make distributions. Adjusted EBITDA is a supplemental financial measure that management and external users of our consolidated financial statements, such as industry analysts, investors, commercial banks and rating agencies, use to assess the following, among other measures:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash flow to make distributions; and
- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Adjusted EBITDA increased by $30.2 million for the three months ended June 30, 2015, primarily due to a $59.2 million increase in total revenues and a $1.6 million increase in distributions from equity investees. These amounts were partially offset by a $24.9 million increase in cost of product, a $1.5 million increase in property and other tax expense, and a $4.6 million increase in operation and maintenance expenses.

Adjusted EBITDA increased by $63.0 million for the six months ended June 30, 2015, primarily due to a $146.4 million increase in total revenues and a $10.9 million increase in distributions from equity investees. These amounts were partially offset by a $68.9 million increase in cost of product, a $21.5 million increase in operation and maintenance expenses, a $2.7 million increase in property and other tax expense, and a $1.7 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Distributable cash flow. We define "Distributable cash flow" as Adjusted EBITDA, plus interest income, plus the net settlement amounts from the sale and/or purchase of natural gas, drip condensate and NGLs under our commodity price swap agreements to the extent such amounts are not recognized as Adjusted EBITDA, less net cash paid for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures and income taxes. We compare Distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the Coverage ratio of 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 with Anadarko, Distributable cash flow is not a reflection of our ability to generate cash from operations.

Distributable cash flow increased by $29.5 million for the three months ended June 30, 2015, primarily due to a $30.2 million increase in Adjusted EBITDA and a $2.6 million decrease in cash paid for maintenance capital expenditures, partially offset by a $3.2 million increase in net cash paid for interest expense.

Distributable cash flow increased by $52.4 million for the six months ended June 30, 2015, primarily due to a $63.0 million increase in Adjusted EBITDA, partially offset by a $10.5 million increase in net cash paid for interest expense.

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

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
thousands	2015 (Restated)	2014	2015 (Restated)	2014
Reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP to Operating income (loss)				
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$255,342	$222,913	$489,194	$418,684
Adjusted gross margin for crude/NGL assets	22,018	21,507	42,202	32,296
Adjusted gross margin attributable to Western Gas Partners, LP	277,360	244,420	531,396	450,980
Adjusted gross margin attributable to noncontrolling interest	4,661	4,935	9,469	10,029
Equity income, net	18,941	13,008	37,161	22,259
Reimbursed electricity-related charges recorded as revenues	13,221	10,036	25,031	16,553
Less:				
Distributions from equity investees	25,902	24,328	47,572	36,641
Operation and maintenance	70,048	65,440	138,007	116,534
General and administrative	8,667	8,445	19,179	17,349
Property and other taxes	8,775	7,316	17,298	14,550
Depreciation and amortization	61,485	44,962	123,555	85,857
Impairments	1,268	343	273,892	1,533
Operating income (loss)	$138,038	$121,565	$(16,446)	$227,357

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thousands	Three Months Ended June 30, 2015 (Restated)	2014	Six Months Ended June 30, 2015 (Restated)	2014
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net income (loss) attributable to Western Gas Partners, LP				
Adjusted EBITDA attributable to Western Gas Partners, LP	$205,452	$175,289	$386,352	$323,395
Less:				
Distributions from equity investees	25,902	24,328	47,572	36,641
Non-cash equity-based compensation expense	1,163	1,057	2,275	2,154
Interest expense	27,604	20,864	50,564	34,825
Income tax expense	—	2,523	3,416	4,308
Depreciation and amortization (1)	60,835	44,319	122,257	84,577
Impairments	1,268	343	273,892	1,533
Add:				
Equity income, net	18,941	13,008	37,161	22,259
Interest income – affiliates	4,225	4,225	8,450	8,450
Other income (1) (2)	68	79	137	157
Income tax benefit	1,710	—	1,710	—
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net cash provided by operating activities				
Adjusted EBITDA attributable to Western Gas Partners, LP	$205,452	$175,289	$386,352	$323,395
Adjusted EBITDA attributable to noncontrolling interest	3,463	4,090	7,335	8,416
Interest income (expense), net	(23,379)	(16,639)	(42,114)	(26,375)
Uncontributed cash-based compensation awards	(68)	(20)	(145)	33
Accretion and amortization of long-term obligations, net	4,958	678	7,070	1,358
Current income tax benefit (expense)	(285)	(1,298)	(418)	(2,090)
Other income (expense), net (2)	71	82	142	163
Distributions from equity investments in excess of cumulative earnings	(5,574)	(7,804)	(8,538)	(9,848)
Changes in operating working capital:				
Accounts receivable, net	(28,463)	(8,421)	(46,135)	(23,860)
Accounts and natural gas imbalance payables and accrued liabilities, net	(10,000)	(2,439)	(118)	4,267
Other	(744)	2,369	(1,964)	4,247
Net cash provided by operating activities	$145,431	$145,887	$301,467	$279,706
Cash flow information of Western Gas Partners, LP				
Net cash provided by operating activities			$301,467	$279,706
Net cash used in investing activities			(349,170)	(801,530)
Net cash provided by financing activities			68,417	531,725

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

(2) Excludes income of zero and $0.1 million for the three months ended June 30, 2015 and 2014, respectively, and zero and $0.5 million for the six months ended June 30, 2015 and 2014, respectively, related to a component of a gas processing agreement accounted for as a capital lease.

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thousands except Coverage ratio	Three Months Ended June 30, 2015 (Restated)	2014	Six Months Ended June 30, 2015 (Restated)	2014
Reconciliation of Distributable cash flow to Net income (loss) attributable to Western Gas Partners, LP and calculation of the Coverage ratio				
Distributable cash flow	$173,308	$143,794	$321,305	$268,920
Less:				
Distributions from equity investees	25,902	24,328	47,572	36,641
Non-cash equity-based compensation expense	1,163	1,057	2,275	2,154
Interest expense, net (non-cash settled) [1]	4,190	—	5,610	—
Income tax (benefit) expense	(1,710)	2,523	1,706	4,308
Depreciation and amortization [2]	60,835	44,319	122,257	84,577
Impairments	1,268	343	273,892	1,533
Add:				
Equity income, net	18,941	13,008	37,161	22,259
Cash paid for maintenance capital expenditures [2]	10,262	12,849	22,894	22,993
Capitalized interest	2,693	2,007	5,787	5,447
Cash paid for (reimbursement of) income taxes	—	—	(138)	(340)
Other income [2] [3]	68	79	137	157
Net income (loss) attributable to Western Gas Partners, LP	$113,624	$99,167	$(66,166)	$190,223
Distributions declared [4]				
Limited partners	$96,431		$189,570	
General partner	43,305		83,369	
Total	$139,736		$272,939	
Coverage ratio	1.24 x		1.18 x	

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

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

(3) Excludes income of zero and $0.1 million for the three months ended June 30, 2015 and 2014, respectively, and zero and $0.5 million for the six months ended June 30, 2015 and 2014, respectively, related to a component of a gas processing agreement accounted for as a capital lease.

(4) Reflects cash distributions of $0.750 and $1.475 per unit declared for the three and six months ended June 30, 2015.

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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 June 30, 2015, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional equity or debt securities. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, capital requirements and other factors, and will be determined by the Board of Directors of our general partner on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including equity and debt issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under our RCF to pay distributions or fund other short-term working capital requirements.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our initial public offering ("IPO") and have increased our quarterly distribution each quarter since the second quarter of 2009. On July 16, 2015, the Board of Directors of our general partner declared a cash distribution to our unitholders of $0.750 per unit, or $139.7 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution is payable on August 12, 2015, to unitholders of record at the close of business on July 31, 2015. In connection with the closing of the DBM acquisition in November 2014, we issued Class C units that will receive distributions in the form of additional Class C units until the end of 2017, unless earlier converted (see Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A). The Class C unit distribution, if paid in cash, would have been $8.3 million for the second quarter of 2015.

Management continuously monitors our leverage position and coordinates our capital expenditure program, quarterly distributions and acquisition strategy with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or to refinance outstanding debt balances with longer term notes. To facilitate a potential debt or equity securities issuance, we have the ability to sell securities under our shelf registration statements. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read Part II, Item 1A—Risk Factors of this Form 10-Q/A.

Working capital. As of June 30, 2015, we had $59.4 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. As of June 30, 2015, we had $917.2 million available for borrowing under our RCF.

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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 2015, the general partner's Board of Directors has approved Estimated Maintenance Capital Expenditures (as defined in our partnership agreement) of $19.8 million per quarter); or

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

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

	Six Months Ended June 30,	
thousands	2015	2014
Acquisitions	$13,482	$360,952
Expansion capital expenditures	$315,078	$367,136
Maintenance capital expenditures	23,100	23,188
Total capital expenditures (1) (2)	$338,178	$390,324
Capital incurred (2) (3)	$287,389	$373,649

(1) Maintenance capital expenditures for the six months ended June 30, 2015 and 2014, are presented net of zero and $0.2 million, respectively, of contributions in aid of construction costs from affiliates. Capital expenditures for the six months ended June 30, 2014, included $30.8 million of pre-acquisition capital expenditures for the DBJV system.

(2) Includes the noncontrolling interest owner's share of Chipeta's capital expenditures for all periods presented. For the six months ended June 30, 2015 and 2014, included $5.8 million and $5.4 million, respectively, of capitalized interest.

(3) Capital incurred for the six months ended June 30, 2014, included $30.8 million of pre-acquisition capital incurred for the DBJV system.

Acquisitions during the first six months of 2015 included equipment purchases from Anadarko and the post-closing purchase price adjustments related to the DBM acquisition. Acquisitions during the first six months of 2014 included the TEFR Interests. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Capital expenditures, excluding acquisitions, decreased by $52.1 million for the six months ended June 30, 2015. Expansion capital expenditures decreased by $52.1 million (net of a $0.3 million increase in capitalized interest) for the six months ended June 30, 2015, primarily due to a decrease of $69.7 million at the DJ Basin complex related to compression projects in 2014 and less activity in 2015 at the Lancaster plant. In addition, there were decreases of $11.2 million at the Brasada complex, $10.5 million at the Hilight system and $10.5 million at the Red Desert complex. These decreases were partially offset by an increase of $53.1 million due to the acquisition of DBM in November 2014.

Our estimated total capital expenditures for the year ending December 31, 2015, including our 75% share of Chipeta's capital expenditures, but excluding equity investments and acquisitions, are $629 million to $689 million. Total capital expenditures including equity investments, but excluding acquisitions, are expected to be between $640 million and $700 million. We have updated our outlook for maintenance capital expenditures from an originally reported range between 8% and 11% of Adjusted EBITDA, to a current range between 7% and 10% of Adjusted EBITDA.

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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:

	Six Months Ended June 30,	
thousands	2015	2014
Net cash provided by (used in):		
Operating activities	$301,467	$279,706
Investing activities	(349,170)	(801,530)
Financing activities	68,417	531,725
Net increase (decrease) in cash and cash equivalents	$20,714	$9,901

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

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

- $338.2 million of capital expenditures, primarily related to the construction of Train IV at the DBM complex, construction of Lancaster Train II (part of the DJ Basin complex) and expansion at the DBJV system;
- $10.0 million of cash paid for equipment purchases from Anadarko;
- $6.8 million of cash contributed to equity investments, primarily related to expansion projects at White Cliffs, TEP and FRP;
- $3.5 million of cash paid for post-closing purchase price adjustments related to the DBM acquisition; and
- $8.5 million of distributions from equity investments in excess of cumulative earnings.

Net cash used in investing activities for the six months ended June 30, 2014, included the following:

- $390.3 million of capital expenditures, net of $0.2 million of contributions in aid of construction costs from affiliate, primarily related to the construction of Lancaster Train I, as well as compression expansion projects, all part of the DJ Basin complex;
- $356.3 million of cash paid for the acquisition of the TEFR Interests;
- $37.5 million of cash paid related to the construction of the Front Range Pipeline, which was completed in March 2014;
- $10.0 million of cash paid for White Cliffs expansion projects;
- $4.7 million of cash paid for equipment purchases from Anadarko; and
- $9.8 million of distributions from equity investments in excess of cumulative earnings.

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

- $489.7 million of net proceeds from the 2025 Notes offering in June 2015, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under our RCF;
- $280.0 million of borrowings to fund capital expenditures and for general partnership purposes;
- $57.4 million of net proceeds from sales of common units under the $500.0 million COP (as defined and discussed in Equity Offerings within this Item 2). Net proceeds were used for general partnership purposes, including funding capital expenditures;
- $30.1 million of net contributions from Anadarko representing intercompany transactions attributable to the acquisition of DBJV;
- $259.2 million of distributions paid to our unitholders; and
- $7.2 million of distributions paid to the noncontrolling interest owner of Chipeta.

Net cash provided by financing activities for the six months ended June 30, 2014, included the following:

- $389.5 million of net proceeds from the 2044 Notes offering in March 2014, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under our RCF;
- $350.0 million of borrowings to fund the acquisition of the TEFR Interests;
- $240.0 million of borrowings to fund capital expenditures and general partnership purposes;
- $100.0 million of net proceeds from the offering of additional 2018 Notes in March 2014, after underwriting discounts, original issue premium and offering costs, part of which was used to repay a portion of the outstanding borrowings under our RCF;
- $74.3 million of net proceeds from sales of common units under the $125.0 million COP (as defined and discussed in Equity Offerings within this Item 2), including net proceeds from capital contributions by our general partner;
- $39.0 million of net contributions from Anadarko representing intercompany transactions attributable to the acquisitions of DBJV and the TEFR Interests;
- $18.1 million of net proceeds related to the partial exercise of the underwriters’ over-allotment option granted in connection with our December 2013 equity offering;
- $0.4 million of net proceeds from a capital contribution by our general partner after common units were issued in conjunction with the acquisition of the TEFR Interests;
- $191.4 million of distributions paid to our unitholders; and
- $7.9 million of distributions paid to the noncontrolling interest owner of Chipeta.

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Debt and credit facility. At June 30, 2015, our debt consisted of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the “2021 Notes”), $670.0 million aggregate principal amount of 4.000% Senior Notes due 2022 (the “2022 Notes”), $350.0 million aggregate principal amount of 2.600% Senior Notes due 2018 (the “2018 Notes”), $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 (the “2044 Notes”), $500.0 million aggregate principal amount of 3.950% Senior Notes due 2025 (the “2025 Notes”), and $270.0 million of borrowings outstanding under our RCF. As of June 30, 2015, the carrying value of our outstanding debt was $2.7 billion. See Note 9—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Senior Notes. The 2025 Notes issued in June 2015 were offered at a price to the public of 98.789% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2025 Notes is 4.205%. Interest is paid semi-annually on June 1 and December 1 of each year. Proceeds (net of underwriting discount of $3.3 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under our RCF.
At June 30, 2015, we were in compliance with all covenants under the indentures governing our outstanding notes.

Revolving credit facility. As of June 30, 2015, we had $270.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $917.2 million available for borrowing under the RCF, which matures in February 2019. At June 30, 2015, the interest rate on the RCF was 1.49%, the facility fee rate was 0.20% and we were in compliance with all covenants under the RCF.

Deferred purchase price obligation - Anadarko. The consideration to be paid for the acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. The cash payment will be equal to eight multiplied by (a) the average of our share in the Net Earnings (see definition below) of the DBJV system for the calendar years 2018 and 2019, less (b) our share of all capital expenditures incurred for the DBJV system between March 1, 2015, and February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to the DBJV system on an accrual basis. As of the acquisition date, the estimated future payment obligation was $282.8 million, which had a net present value of $174.3 million, using a discount rate of 10%. As of June 30, 2015, the net present value of this obligation was $179.9 million and has been recorded on the consolidated balance sheet under Deferred purchase price obligation - Anadarko. Accretion expense for the three and six months ended June 30, 2015, was $4.2 million and $5.6 million, respectively, and has been recorded as a charge to interest expense. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

Registered securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statements on file with the SEC.
In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $125.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. See Note 4—Equity and Partners’ Capital (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for a discussion of trades completed under the $125.0 million COP. As of December 31, 2014, we had used all the capacity to issue common units under this registration statement.
In August 2014, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $500.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. See Note 4—Equity and Partners’ Capital (Restated) in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for a discussion of trades completed under 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. A substantial portion of our throughput, however, comes from producers that have investment-grade ratings.

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

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko, which was issued concurrently with the closing of our IPO. 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 substantial majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, and are subject to performance risk thereunder. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

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

CONTRACTUAL OBLIGATIONS

Our contractual obligations include, among other things, a revolving credit facility, other third-party long-term debt, capital obligations related to our expansion projects and various operating leases. Refer to Note 9—Debt and Interest Expense and Note 10—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A for an update to our contractual obligations as of June 30, 2015, including, but not limited to, increases in committed capital.

OFF-BALANCE SHEET ARRANGEMENTS

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

RECENT ACCOUNTING DEVELOPMENTS

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

To mitigate our exposure to a substantial majority of the changes in commodity prices as a result of the purchase and sale of natural gas, condensate or NGLs, we currently have in place commodity price swap agreements with Anadarko expiring at various times through December 2016. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex (excluding the Granger straddle plant) expired without renewal. During the second quarter, we extended our commodity price swap agreements with Anadarko for the DJ Basin complex from July 1, 2015, through December 31, 2015, and for the Hugoton system from October 1, 2015, through December 31, 2015. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part I, Item 1 of this Form 10-Q/A.

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

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

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

Interest rate risk. Interest rates during the six months ended June 30, 2015, were low compared to historic rates. As of June 30, 2015, we had $270.0 million of outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). If interest rates rise, our future financing costs could increase. A 10% change in LIBOR would have resulted in a nominal change in net income (loss) and the fair value of the borrowings under the RCF at June 30, 2015.

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

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership's general partner (for purposes of this Item 4, "Management") performed an evaluation of the Partnership's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 ("Exchange Act"). Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. At the time of the Original Filing on July 30, 2015, Management concluded that the Partnership's disclosure controls and procedures were effective as of June 30, 2015. Subsequent to that evaluation, Management determined that a material weakness in internal control over financial reporting, as further discussed below, existed as of June 30, 2015. As a result of the determination of a material weakness in the Partnership's internal control over financial reporting, Management has now concluded that the Partnership's disclosure controls and procedures were not effective as of June 30, 2015.
A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Partnership's annual or interim financial statements will not be prevented or detected on a timely basis. In connection with the preparation of the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, the Partnership determined that there was an error in the impairment test calculation performed as of March 31, 2015. Specifically, the impact of the Partnership's commodity price swap agreements with Anadarko was incorrectly included when performing an assessment to identify a triggering event that would necessitate a calculation to determine whether the net book value of certain midstream assets exceeded their fair value. Management concluded that this deficiency in internal control over financial reporting related to an inadequate understanding of GAAP impairment standards by certain individuals, resulting in a failure to follow the Partnership's accounting policies. This failure to identify a triggering event that would have led to an asset impairment constituted a material weakness as defined in the SEC regulations. This material weakness resulted in the misstatement of impairment expense and in the restatement of the unaudited consolidated financial statements for the interim periods ended March 31, 2015, June 30, 2015, and September 30, 2015.
We performed additional analysis and procedures with respect to accounts impacted by the material weakness in order to conclude that our unaudited consolidated financial statements in this Form 10-Q/A as of June 30, 2015, and for the three and six months ended June 30, 2015 and 2014, are fairly presented, in all material respects, in accordance with GAAP.

Remediation Plan. The Partnership is remediating this material weakness by, among other things, implementing a training program for the personnel involved in the impairment determination processes and controls to ensure business understanding and the proper application of GAAP related to the impairment of long-lived assets. The actions taken by the Partnership are subject to ongoing senior management review and Audit Committee oversight. The foregoing actions will begin immediately, and Management expects that efforts to remediate the material weakness will be completed by the end of the second quarter of 2016. As the Partnership continues to evaluate and work to improve its internal control over financial reporting, Management may execute additional measures to address the material weakness or modify the remediation plan described above and will continue to review and make necessary changes to the overall design of the Partnership's internal controls.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended June 30, 2015, that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

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

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

Item 1A. Risk Factors

Security holders and potential investors in our securities should carefully consider the risk factors included below, as well as those set forth under Part I, Item 1A in our Form 10-K for the year ended December 31, 2014, 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, 2014, 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.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration's proposal, or other similar proposals, could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

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In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.
Any modifications to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

During the three and six months ended June 30, 2015, in connection with the quarterly distribution for the Class C units the Partnership issued the following additional Class C units ("PIK Class C units") to APC Midstream Holdings, LLC, the holder of the Class C units:

thousands except unit amounts For the Quarters Ended	PIK Class C Units	Implied Fair Value	Date of Distribution
2014			
December 31	45,711	$3,072	February 2015
2015			
March 31	118,230	$8,101	May 2015

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

Item 6. Exhibits

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

Exhibit Number	Description
2.1#	Contribution, Conveyance and Assumption Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, Anadarko Petroleum Corporation, WGR Holdings, LLC, Western Gas Resources, Inc., WGR Asset Holding Company LLC, Western Gas Operating, LLC and WGR Operating, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP’s Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
2.2#	Contribution Agreement, dated as of November 11, 2008, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on November 13, 2008, File No. 001-34046).
2.3#	Contribution Agreement, dated as of July 10, 2009, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Anadarko Uintah Midstream, LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
2.4#	Contribution Agreement, dated as of January 29, 2010 by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, Mountain Gas Resources LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on February 3, 2010 File No. 001-34046).
2.5#	Contribution Agreement, dated as of July 30, 2010, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
2.6#	Purchase and Sale Agreement, dated as of January 14, 2011, by and among Western Gas Partners, LP, Kerr-McGee Gathering LLC and Encana Oil & Gas (USA) Inc. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on January 18, 2011 File No. 001-34046).
2.7#	Contribution Agreement, dated as of December 15, 2011, by and among Western Gas Resources, Inc., WGR Asset Holding Company LLC, WGR Holdings, LLC, Western Gas Holdings, LLC, WES GP, Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on December 15, 2011, File No. 001-34046).
2.8#	Contribution Agreement, dated as of February 27, 2013, by and among Anadarko Marcellus Midstream, L.L.C., Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, Anadarko Petroleum Corporation and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP’s Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
2.9#	Contribution Agreement, dated as of February 27, 2014, by and among WGR Asset Holding Company, LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP and Anadarko Petroleum Corporation (incorporated by reference to Exhibit 2.9 to Western Gas Partners, LP’s Annual Report on Form 10-K filed on February 28, 2014, File No. 001-34046).

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

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Exhibit Number	Description
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).
3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated July 22, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated January 29, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
3.7	Amendment No. 5 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 2, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
3.8	Amendment No. 6 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated July 8, 2011 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 8, 2011, File No. 001-34046).
3.9	Amendment No. 7 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated January 13, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 17, 2012, File No. 001-34046).
3.10	Amendment No. 8 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 1, 2012 (incorporated by reference to Exhibit 3.10 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on August 2, 2012, File No. 001-34046).
3.11	Amendment No. 9 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated December 12, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
3.12	Amendment No. 10 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 1, 2013 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
3.13	Amendment No. 11 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 3, 2014 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2014, File No. 001-34046).
3.14	Amendment No. 12 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated November 25, 2014 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on November 25, 2014, File No. 001-34046).
3.15	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).
3.16	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).

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Exhibit Number	Description
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).
4.2	Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.3	First Supplemental Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.4	Form of 5.375% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.5	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).
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.7	Form of 2.600% Senior Notes due 2018 (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	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).
4.9	Form of 5.450% Senior Notes due 2044 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 20, 2014, File No. 001-34046).
4.10	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).
4.11	Form of 3.950% Senior Notes due 2025 (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).
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

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

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WESTERN GAS PARTNERS, LP

February 3, 2016

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

February 3, 2016

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