Western Gas Partners LP
Form 10-K
February 23, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

Or

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

For the transition period from to

Commission file number: 001-34046

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

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes þ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes No þ

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

The aggregate market value of the registrant's common units representing limited partner interests held by non-affiliates of the registrant was $3.9 billion on June 30, 2016, based on the closing price as reported on the New York Stock Exchange.

At February 21, 2017, there were 130,671,970 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, references to “we,” “us,” “our,” the “Partnership” or “Western Gas Partners, LP” refer to Western Gas Partners, LP and its subsidiaries. As used in this Form 10-K, the terms and definitions below have the following meanings:

AESC: Anadarko Energy Services Company.

Affiliates: Subsidiaries of Anadarko, excluding us, but including equity interests in Fort Union, White Cliffs, Rendezvous, the Mont Belvieu JV, TEP, TEG, and FRP.

AMH: APC Midstream Holdings, LLC.

AMM: Anadarko Marcellus Midstream, L.L.C.

Anadarko: Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner.

Anadarko-Operated Marcellus Interest: Our 33.75% interest in the Larry’s Creek, Seely and Warrensville gas gathering systems and related facilities located in northern Pennsylvania.

April 2016 Series A units: The 7,892,220 Series A Preferred units issued pursuant to the full exercise of the option granted in connection with the issuance of the March 2016 Series A units.

Barrel or Bbl: 42 U.S. gallons measured at 60 degrees Fahrenheit.

Bbls/d: Barrels per day.

Board of Directors or Board: The board of directors of our general partner.

Btu: British thermal unit; the approximate amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Chipeta: Chipeta Processing, LLC.

Chipeta LLC agreement: Chipeta’s limited liability company agreement, as amended and restated as of July 23, 2009.

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

COP: Continuous offering programs.

Cryogenic: The process in which liquefied gases are used to bring natural gas volumes to very low temperatures (below approximately -238 degrees Fahrenheit) to separate natural gas liquids from natural gas. Through cryogenic processing, more natural gas liquids are extracted than when traditional refrigeration methods are used.

DBJV: Delaware Basin JV Gathering LLC.

DBJV system: A gathering system and related facilities located in the Delaware Basin in Loving, Ward, Winkler and Reeves Counties in West Texas.

DBM: Delaware Basin Midstream, LLC.

DBM complex: The cryogenic processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico.

Delivery point: The point where hydrocarbons are delivered by a processor or transporter to a producer, shipper or purchaser, typically the inlet at the interconnection between the gathering or processing system and the facilities of a third-party processor or transporter.

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DJ Basin complex: The Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.
Drip condensate: Heavier hydrocarbon liquids that fall out of the natural gas stream and are recovered in the gathering system without processing.
Dry gas: A gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.
EBITDA: Earnings before interest, taxes, depreciation, and amortization. For a definition of “Adjusted EBITDA,” see the caption How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K.
End-use markets: The ultimate users/consumers of transported energy products.
Equity investment throughput: Our 14.81% share of average Fort Union throughput, 22% share of average Rendezvous throughput, 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput.
Exchange Act: The Securities Exchange Act of 1934, as amended.
FERC: The Federal Energy Regulatory Commission.
Fitch: Fitch Ratings Inc.
Fort Union: Fort Union Gas Gathering, LLC.
Fractionation: The process of applying various levels of higher pressure and lower temperature to separate a stream of natural gas liquids into ethane, propane, normal butane, isobutane and natural gasoline for end-use sale.
FRP: Front Range Pipeline LLC.
GAAP: Generally accepted accounting principles in the United States.
General partner or GP: Western Gas Holdings, LLC.
Gpm: Gallons per minute, when used in the context of amine treating capacity.
Hydraulic fracturing: The injection of fluids into the wellbore to create fractures in rock formations, stimulating the production of oil or gas.
IDRs: Incentive distribution rights.
Imbalance: Imbalances result from (i) differences between gas and NGL volumes nominated by customers and gas and NGL volumes received from those customers and (ii) differences between gas and NGL volumes received from customers and gas and NGL volumes delivered to those customers.
Initial assets: The assets and liabilities of Anadarko Gathering Company LLC, Pinnacle Gas Treating LLC (sold by the Partnership in 2015) and MIGC, LLC, which Anadarko contributed to us concurrently with the closing of our IPO in May 2008.
IPO: Initial public offering.
Joule-Thompson (JT): A type of processing plant that uses the Joule-Thompson effect to cool natural gas by expanding the gas from a higher pressure to a lower pressure which reduces the temperature.
LIBOR: London Interbank Offered Rate.
March 2016 Series A units: The 14,030,611 Series A Preferred units issued in March 2016 in connection with the acquisition of Springfield.
MBbls/d: One thousand barrels per day.

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MGR: Mountain Gas Resources, LLC.
MGR assets: The Red Desert complex and the Granger straddle plant.
MIGC: MIGC, LLC.
MLP: Master limited partnership.
MMBtu: One million British thermal units.
MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
Mont Belvieu JV: Enterprise EF78 LLC.
Moody’s: Moody’s Investors Service Inc.
Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Non-Operated Marcellus Interest: Our 33.75% interest in the Liberty and Rome gas gathering systems and related facilities located in northern Pennsylvania.
Nuevo: Nuevo Midstream, LLC.
NYSE: New York Stock Exchange.
NYMEX: New York Mercantile Exchange.
OTTCO: Overland Trail Transmission, LLC.
PIK Class C units: Additional Class C units issued as quarterly distributions to the holder of our Class C units.
Play: A group of gas or oil fields that contain known or potential commercial amounts of petroleum and/or natural gas.
Produced water: Byproduct associated with the production of crude oil and natural gas that often contains a number of dissolved solids and other materials found in oil and gas reservoirs.
RCF: Our senior unsecured revolving credit facility.
Receipt point: The point where hydrocarbons are received by or into a gathering system, processing facility or transportation pipeline.
Red Desert complex: The Patrick Draw processing plant, the Red Desert processing plant, associated gathering lines, and related facilities.
Refrigeration: A method of processing natural gas by reducing the gas temperature with the use of an external refrigeration system.
Rendezvous: Rendezvous Gas Services, LLC.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
S&P: Standard and Poor’s Financial Services LLC.
SEC: U.S. Securities and Exchange Commission.
Springfield: Springfield Pipeline LLC.

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Springfield interest: Springfield’s 50.1% interest in the Springfield system.
Springfield gas gathering system: A gas gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield oil gathering system: An oil gathering system and related facilities located in Dimmit, La Salle, Maverick and Webb Counties in South Texas.
Springfield system: The Springfield gas gathering system and Springfield oil gathering system.
Stabilization: The process of separating very light hydrocarbon gases, methane and ethane in particular, from heavier hydrocarbon components. This process reduces the volatility of the liquids during transportation and storage.
Tailgate: The point at which processed natural gas and/or natural gas liquids leave a processing facility for end-use markets.
TEFR Interests: The interests in TEP, TEG and FRP.
TEG: Texas Express Gathering LLC.
TEP: Texas Express Pipeline LLC.
Wellhead: The point at which the hydrocarbons and water exit the ground.
WES LTIP: Western Gas Partners, LP 2008 Long-Term Incentive Plan.
WGP: Western Gas Equity Partners, LP.
WGP GP: Western Gas Equity Holdings, LLC, the general partner of WGP.
WGP LTIP: Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan.
WGRI: Western Gas Resources, Inc.
White Cliffs: White Cliffs Pipeline, LLC.
2018 Notes: Our 2.600% Senior Notes due 2018.
2021 Notes: Our 5.375% Senior Notes due 2021.
2022 Notes: Our 4.000% Senior Notes due 2022.
2025 Notes: Our 3.950% Senior Notes due 2025.
2026 Notes: Our 4.650% Senior Notes due 2026.
2044 Notes: Our 5.450% Senior Notes due 2044.
$125.0 million COP: The COP contemplated by the registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of our common units.
$500.0 million COP: The COP contemplated by the registration statement filed with the SEC in August 2014 authorizing the issuance of up to an aggregate of $500.0 million of our common units.

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PART I

Items 1 and 2. Business and Properties

GENERAL OVERVIEW

We are a growth-oriented Delaware MLP formed by Anadarko in 2007 to acquire, own, develop and operate midstream energy assets. We are engaged in the business of gathering, compressing, treating, processing and transporting natural gas, and gathering, stabilizing and transporting condensate, NGLs and crude oil. We are also currently constructing two produced-water disposal systems in West Texas, which are expected to be placed in service during the second quarter of 2017. We provide these midstream services for Anadarko, as well as for third-party producers and customers. Our common units are publicly traded on the NYSE under the symbol “WES.”
WGP, a Delaware MLP formed by Anadarko in September 2012, owns our general partner and a significant limited partner interest in us. WGP’s common units are publicly traded on the NYSE under the symbol “WGP.” WGP GP is a wholly owned subsidiary of Anadarko.

Available information. We electronically file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents with the SEC under the Exchange Act. From time to time, we may also file registration and related statements pertaining to equity or debt offerings.
We provide access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing such materials with the SEC, on our website located at www.westerngas.com. The public may also read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The public may also obtain such reports from the SEC’s website at www.sec.gov.
Our Corporate Governance Guidelines, Code of Ethics for our Chief Executive Officer and Senior Financial Officers, Code of Business Conduct and Ethics and the charters of the Audit Committee and the Special Committee of our Board of Directors are also available on our website. We will also provide, free of charge, a copy of any of our governance documents listed above upon written request to our general partner’s corporate secretary at our principal executive office. Our principal executive offices are located at 1201 Lake Robbins Drive, The Woodlands, TX 77380-1046. Our telephone number is 832-636-6000.

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OUR ASSETS AND AREAS OF OPERATION

As of December 31, 2016, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	11	4	5	2
Treating facilities	12	12	—	3
Natural gas processing plants/trains	20	5	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania and Texas. The following table provides information regarding our assets by geographic region, as of and for the year ended December 31, 2016, excluding Train VI at the DBM complex, which is currently under construction in West Texas (see Assets Under Development within these Items 1 and 2):

Area	Asset Type	Miles of Pipeline (1)	Approximate Number of Active Receipt Points (1)	Compression (HP) (1)	Processing or Treating Capacity (MMcf/d) (1)	Processing or Treating Capacity (MBbls/d) (1)	Average Gathering, Processing and Transportation Throughput (MMcf/d) (2)	Average Gathering, Treating and Transportation Throughput (MBbls/d) (3)
Rocky Mountains	Gathering, Processing and Treating	7,726	4,624	548,078	3,377	—	2,252	—
	Transportation	1,726	46	43,634	—	—	95	28
North-central Pennsylvania	Gathering	673	404	88,300	—	—	770	—
Texas	Gathering, Processing and Treating	1,980	891	432,804	1,260	284	903	87
	Transportation	1,175	13	40,895	—	—	—	69
Total		13,280	5,978	1,153,711	4,637	284	4,020	184

(1) All system metrics are presented on a gross basis and include owned, rented and leased compressors at certain facilities. Includes horsepower associated with liquid pump stations.

(2) Includes 100% of Chipeta throughput, 50% of Newcastle and DBJV system throughput, 50.1% of Springfield gas gathering throughput, 22% of Rendezvous throughput and 14.81% of Fort Union throughput, but excludes throughput related to the Hugoton system (44 MMcf/d for the ten months ended October 31, 2016) prior to its divestiture in October 2016 (see Acquisitions and Divestitures within these Items 1 and 2).

(3) Represents total throughput measured in barrels, consisting of throughput on our Chipeta NGL pipeline and an NGL line at our Brasada complex, our 50.1% share of average Springfield oil gathering system throughput, 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. See Properties below for further descriptions of these systems.

Our operations are organized into a single operating segment that engages in gathering, compressing, treating, processing and transporting natural gas, and gathering, stabilizing and transporting condensate, NGLs and crude oil.

We are also currently constructing two produced-water disposal systems in West Texas, which are expected to be placed in service during the second quarter of 2017. We provide these services for Anadarko and third-party producers and customers in the United States. See Part II, Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2016, 2015 and 2014.

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ACQUISITIONS AND DIVESTITURES

Acquisitions. On March 14, 2016, we acquired Anadarko's interest in Springfield, which owns a 50.1% interest in oil and natural gas gathering systems located in Dimmit, La Salle, Maverick and Webb Counties in South Texas for $750.0 million. We financed the cash portion of the acquisition through: (i) borrowings of $247.5 million under our RCF, (ii) the issuance of 835,841 of our common units to WGP and (iii) the issuance of Series A Preferred units to private investors. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for further information regarding the Series A Preferred units.

Divestitures. In October 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations. See Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Presentation of Partnership assets. The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K) by us as of December 31, 2016. Because Anadarko controls us through its 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 II, Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control.

EQUITY OFFERINGS

$500 million COP. We issued no common units under the $500.0 million COP during the year ended December 31, 2016.

Series A Preferred units. In March 2016, we issued the March 2016 Series A units to private investors for a cash purchase price of $32.00 per unit, generating proceeds of $440.0 million (net of fees and expenses, but including a 2.0% transaction fee paid to the private investors), which were used to fund a portion of the Springfield acquisition. In April 2016, we issued the April 2016 Series A units pursuant to the full exercise of an option granted in connection with the March 2016 Series A units issuance, generating net proceeds of $246.9 million, which were used to pay down amounts borrowed under our RCF in connection with the Springfield acquisition. See Note 4—Equity and Partners' Capital and Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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STRATEGY

Our primary business objective is to continue to increase our cash distributions per unit over time. To accomplish this objective, we intend to execute the following strategy:

- Capitalizing on organic growth opportunities. We expect to grow certain of our systems organically over time by meeting Anadarko’s and our other customers’ midstream service needs that result from their drilling activity in our areas of operation. We continually evaluate economically attractive organic expansion opportunities in existing or new areas of operation that allow us to leverage our infrastructure, operating expertise and customer relationships to meet new or increased demand of our services.

- Pursuing accretive acquisitions. We expect to continue to pursue accretive acquisitions of midstream energy assets from Anadarko and third parties.

- Increasing third-party volumes to our systems. We continue to actively market our midstream services to, and pursue strategic relationships with, third-party producers and customers with the intention of attracting additional volumes and/or expansion opportunities.

- Managing commodity price exposure. We intend to continue limiting our direct exposure to commodity price changes and promote cash flow stability by pursuing a contract structure designed to mitigate exposure to a majority of the commodity price uncertainty through the use of fee-based contracts and fixed-price hedges.

- Maintaining investment grade metrics. We intend to operate at appropriate leverage and distribution coverage levels in line with other partnerships in our sector that maintain investment grade credit ratings. By maintaining investment grade credit metrics, in part through staying within leverage ratios appropriate for investment-grade partnerships, we believe that we will be able to pursue strategic acquisitions and large growth projects at a lower cost of fixed-income capital, which would enhance our accretion and overall return.

COMPETITIVE STRENGTHS

We believe that we are well positioned to successfully execute our strategy and achieve our primary business objective because of the following competitive strengths:

- Affiliation with Anadarko. We believe Anadarko is motivated to promote and support the successful execution of our business plan and to use its relationships throughout the energy industry, including those with producers and customers in the United States, to pursue projects that help to enhance the value of our business. See Our Relationship with Anadarko Petroleum Corporation below.

- Commodity price and volumetric risk mitigation. Our cash flows are relatively protected from fluctuations caused by commodity price volatility due to (i) the approximately 94% of our Adjusted gross margin attributable to long-term, fee-based agreements and (ii) the commodity price swap agreements that limit our exposure to commodity price changes with respect to a majority of our percent-of-proceeds and keep-whole contracts. For the year ended December 31, 2016, 99% of our Adjusted gross margin was derived from either long-term, fee-based contracts or from percent-of-proceeds or keep-whole agreements that were hedged with commodity price swap agreements. See How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K. On December 1, 2016, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2017. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. In addition, we mitigate volumetric risk by entering into contracts with cost of service or demand charge structures. For the year ended December 31, 2016, and excluding throughput measured in barrels, 54% of our throughput was subject to demand charges and 27% of our throughput was contracted under a cost of service model.

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- Liquidity to pursue expansion and acquisition opportunities. We believe our operating cash flows, borrowing capacity, long-term relationships and reasonable access to debt and equity capital markets provide us with the liquidity to competitively pursue acquisition and expansion opportunities and to execute our strategy across capital market cycles. As of December 31, 2016, we had no outstanding borrowings under our RCF and $4.9 million in outstanding letters of credit issued under our $1.2 billion RCF.

- Substantial presence in basins with historically strong producer economics. Certain of our systems are in areas, such as the Delaware and DJ Basins, and the Eagleford shale, which have historically seen robust producer activity and are considered to have some of the most favorable producer returns for onshore North America. Our assets in these areas serve production where the hydrocarbons contain not only natural gas, but also oil, condensate and NGLs. In addition, our interest in the Anadarko-Operated Marcellus gathering systems serve dry gas production from the Marcellus shale, which is considered to have some of the most abundant low-cost, dry gas reserves due to the overall scale and quality of the underlying resource. See Properties below for further asset descriptions and Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

- Well-positioned and well-maintained assets. We believe that our asset portfolio, which is located in geographically diverse areas of operation, provides us with opportunities to expand and attract additional volumes to our systems from multiple productive reservoirs. Moreover, our portfolio consists of high-quality, well-maintained assets for which we have implemented modern processing, treating, measurement and operating technologies.

- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed eleven related-party acquisitions and six third-party acquisitions, with an aggregate value of $5.6 billion (inclusive of the forecasted cash payment of $56.5 million for the acquisition of DBJV in March 2020, see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Our management team has demonstrated its ability to identify, evaluate, negotiate, consummate and integrate strategic acquisitions and expansion projects, and it intends to use its experience and reputation to continue to grow the Partnership through accretive acquisitions, focusing on opportunities to improve throughput volumes and cash flows.

We believe that we will effectively leverage our competitive strengths to successfully implement our strategy. However, our business involves numerous risks and uncertainties that may prevent us from achieving our primary business objective. For a more complete description of the risks associated with our business, read Risk Factors under Part I, Item 1A of this Form 10-K.

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OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

Our operations and activities are managed by our general partner, which is indirectly controlled by Anadarko through WGP. Anadarko is among the largest independent oil and gas exploration and production companies in the world. Anadarko's upstream oil and gas business explores for and produces natural gas, crude oil, condensate and NGLs. We believe that one of our principal strengths is our relationship with Anadarko, and that Anadarko, through its significant indirect economic interest in us, will continue to be motivated to promote and support the successful execution of our business plan and to pursue projects that help to enhance the value of our business.

For the year ended December 31, 2016, production owned or controlled by Anadarko represented (i) 37% of our natural gas gathering, treating and transportation throughput (excluding equity investment throughput), (ii) 54% of our natural gas processing throughput (excluding equity investment throughput), and (iii) 65% of our crude/NGL gathering, treating and transportation throughput (excluding equity investment throughput). In addition, with respect to the Wattenberg, Haley, Helper and Clawson gathering systems, Anadarko has made dedications to us that will continue to expand as long as additional wells are connected to these gathering systems. In executing our growth strategy, which includes acquiring and constructing additional midstream assets, we use the significant experience of Anadarko's management team.

As of December 31, 2016, WGP held 50,132,046 of our common units, representing a 29.9% limited partner interest in us, and, through its ownership of our general partner, indirectly held 2,583,068 general partner units, representing a 1.5% general partner interest in us, and 100% of our IDRs. As of December 31, 2016, other subsidiaries of Anadarko collectively held 2,011,380 common units and 12,358,123 Class C units, representing an aggregate 8.6% limited partner interest in us. As of December 31, 2016, the public held 78,528,544 common units, representing a 46.9% limited partner interest in us and private investors held 21,922,831 Series A Preferred units, representing a 13.1% limited partner interest in us.

We have commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts at the DJ Basin complex and the MGR assets. These commodity price swap agreements are set to expire in December 2017. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

In connection with our IPO, we entered into an omnibus agreement with Anadarko and our general partner that governs our relationship with Anadarko regarding certain reimbursement and indemnification matters. Although we believe our relationship with Anadarko provides us with a significant advantage in the midstream energy sector, it is also a source of potential conflicts. For example, neither Anadarko nor WGP is restricted from competing with us. Given Anadarko's significant indirect economic interest in us through its ownership of WGP, we believe it will be in Anadarko's best economic interest for it to transfer additional assets to us over time. However, Anadarko continually evaluates acquisitions and divestitures and may elect to acquire, construct or dispose of midstream assets in the future without offering us the opportunity to participate in such transactions. For example, on December 21, 2016, Anadarko announced it had agreed to sell its operated midstream assets in the Marcellus shale to a third party. Should Anadarko choose to pursue additional midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us, nor are we obligated to participate in any such opportunities. We cannot state with any certainty which, if any, opportunities to acquire additional assets from Anadarko may be made available to us or if we will elect, or will have the ability, to pursue any such opportunities. See Risk Factors under Part I, Item 1A and Certain Relationships and Related Transactions, and Director Independence under Part III, Item 13 of this Form 10-K for more information.

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INDUSTRY OVERVIEW

The midstream industry is the link between the exploration for and production of natural gas, NGLs, and crude oil and the delivery of the resulting hydrocarbon components to end-use markets. Operators within this industry create value at various stages along the midstream value chain by gathering production from producers at the wellhead, separating the produced hydrocarbons into various components and delivering these components to end-use markets, and where applicable, gathering and disposing of produced water.
The following diagram illustrates the primary groups of assets found along the midstream value chain:

Natural Gas Midstream Services

Midstream companies provide services with respect to natural gas that are generally classified into the categories described below.

- Gathering. At the initial stages of the midstream value chain, a network of typically smaller diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport raw, or untreated, natural gas to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow gathering of additional production without significant incremental capital expenditures.

- Stabilization. Stabilization is a process that separates the heavier hydrocarbons (which also serve as valuable commodities) that are sometimes found in natural gas, typically referred to as “liquids-rich” natural gas, from the lighter components by using a distillation process or by reducing the pressure and letting the more volatile components flash.

- Compression. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to be gathered more efficiently and delivered into a higher pressure system, processing plant or pipeline. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. Since wells produce at progressively lower field pressures as they deplete, field compression is needed to maintain throughput across the gathering system.

- Treating and dehydration. To the extent that gathered natural gas contains water vapor or contaminants, such as carbon dioxide and hydrogen sulfide, it is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.

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- Processing. The principal components of natural gas are methane and ethane, but most natural gas also contains varying amounts of heavier NGLs and contaminants, such as water and carbon dioxide, sulfur compounds, nitrogen or helium. Natural gas is processed to remove unwanted contaminants that would interfere with pipeline transportation or use of the natural gas and to separate those hydrocarbon liquids from the gas that have higher value as NGLs. The removal and separation of individual hydrocarbons through processing is possible due to differences in weight, boiling point, vapor pressure and other physical characteristics.

- Fractionation. Fractionation is the process of applying various levels of higher pressure and lower temperature to separate a stream of NGLs into ethane, propane, normal butane, isobutane and natural gasoline for end-use sale.

- Storage, transportation and marketing. Once the raw natural gas has been treated or processed and the raw NGL mix has been fractionated into individual NGL components, the natural gas and NGL components are stored, transported and marketed to end-use markets. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to better accommodate seasonal demand and daily supply-demand shifts. We do not currently offer storage services.

Crude Oil Midstream Services

Midstream companies provide services with respect to crude oil that are generally classified into the categories described below.

- Gathering. Crude oil gathering assets provide the link between crude oil production gathered at the well site or nearby collection points and crude oil terminals, storage facilities, long-haul crude oil pipelines and refineries. Crude oil gathering assets generally consist of a network of small-diameter pipelines that are connected directly to the well site or central receipt points and deliver into large-diameter trunk lines. To the extent there are not enough volumes to justify construction of or connection to a pipeline system, crude oil can also be trucked from a well site to a central collection point.

- Stabilization. Crude oil stabilization assets process crude oil to meet vapor pressure specifications. Crude oil delivery points, including crude oil terminals, storage facilities, long-haul crude oil pipelines and refineries, often have specific requirements for vapor pressure and temperature, and for the amount of sediment and water that can be contained in any crude oil delivered to them.

Produced Water Midstream Services

The services provided by us and other midstream companies with respect to produced water are generally classified into the categories described below.

- Gathering. Produced water often accounts for the largest byproduct stream associated with production of crude oil and natural gas. Produced water gathering assets provide the link between well sites or nearby collection points and disposal facilities.

- Disposal. As a byproduct of crude oil and natural gas production, produced water must be recycled or disposed of in order to maintain production. Produced water disposal wells and related facilities remove hydrocarbon products and other sediments from the produced water in compliance with applicable regulations and re-inject it into an underground formation.

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Typical Contractual Arrangements

Midstream services, other than transportation, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical contract types, or combinations thereof, are described below:

- Fee-based. Under fee-based arrangements, the service provider typically receives a fee for each unit of (i) natural gas, NGLs, or crude oil gathered, treated, processed and/or transported, or (ii) produced water disposed of, at its facilities. As a result, the price per unit received by the service provider does not vary with commodity price changes, minimizing the service provider’s direct commodity price risk exposure.

- Percent-of-proceeds, percent-of-value or percent-of-liquids. Percent-of-proceeds, percent-of-value or percent-of-liquids arrangements may be used for gathering and processing services. Under these arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and/or NGLs.

- Keep-whole. Keep-whole arrangements may be used for processing services. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the gas, is returned to the producer. Since some of the gas is used and removed during processing, the processor compensates 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 utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

The above midstream services, as well as the transportation of natural gas, NGLs and crude oil, can be performed on a firm or interruptible basis, as described below:

- Firm. Firm service requires the reservation of capacity by a customer between certain receipt and delivery points or within a processing facility. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus, in specific cases, a usage fee based on the volumes gathered, processed or transported.

- Interruptible. Interruptible service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay only for the volume actually gathered, processed or transported. The obligation to provide this service is limited to available capacity not otherwise used by firm customers, and, as such, customers receiving services under interruptible contracts are not assured capacity.

See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for information regarding recognition of revenue under our contracts.

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PROPERTIES

The following sections describe in more detail the services provided by our assets in our areas of operation as of December 31, 2016.

GATHERING, PROCESSING AND TREATING

Overview - Rocky Mountains - Wyoming

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
Northeast Wyoming	Bison	Treating	3	450	9	14,620	—	—
Northeast Wyoming	Fort Union [1]	Gathering & Treating	3	295	3	5,454	1	315
Northeast Wyoming	Hilight	Gathering & Processing	2	60	40	41,919	1	1,497
Northeast Wyoming	Newcastle [1]	Gathering & Processing	1	3	6	2,660	1	188
Southwest Wyoming	Granger complex [2]	Gathering & Processing	4	500	44	48,617	1	834
Southwest Wyoming	Red Desert complex [3]	Gathering & Processing	1	125	33	58,129	1	1,122
Southwest Wyoming	Rendezvous [4]	Gathering	—	—	5	7,485	1	338
Total			14	1,433	140	178,884	6	4,294

(1) We have a 14.81% interest in Fort Union and a 50% interest in Newcastle.
(2) The Granger complex includes the “Granger straddle plant,” a refrigeration processing plant.
(3) The Red Desert complex includes the Red Desert cryogenic processing plant, which is currently inactive, and the Patrick Draw cryogenic processing plant.
(4) We have a 22% interest in the Rendezvous gathering system, which is operated by a third party.

Northeast Wyoming

Bison treating facility

- Customers. Throughput at the Bison treating facility was from two third party customers for the year ended December 31, 2016. The largest customer provided 78% of the throughput during the year ended December 31, 2016.

- Supply and delivery points. The Bison treating facility treats and compresses gas from coal-bed methane wells in the Powder River Basin of Wyoming. The Bison treating facility is directly connected to Fort Union’s pipeline and the Bison pipeline operated by TransCanada Corporation.

Fort Union gathering system and treating facility

- Customers. Western Gas Wyoming, L.L.C., Copano Pipelines/Rocky Mountains, LLC, Crestone Powder River LLC and Powder River Midstream, LLC hold a majority of the firm capacity on the Fort Union system. To the extent capacity on the system is not used by these customers, it is available to third parties under interruptible agreements.

- Supply. Substantially all of Fort Union’s gas supply is comprised of coal-bed methane volumes that are either produced or gathered by the customers noted above and their affiliates throughout the Powder River Basin. The Fort Union customers noted above gather gas for delivery to Fort Union under contracts with acreage dedications from multiple producers in the heart of the basin and from the coal-bed methane producing area near Sheridan, Wyoming.

- Delivery points. The Fort Union system delivers coal-bed methane gas to the hub in Glenrock, Wyoming, which has access to the following interstate pipelines:

Colorado Interstate Gas Company LLC’s pipeline (“CIG”);
Tallgrass Interstate Gas Transmission system’s pipeline (“TIGT”); and
Wyoming Interstate Company’s pipeline (“WIC”).

These pipelines serve gas markets in the Rocky Mountains and Midwest regions of the United States.

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Hilight gathering system and processing plant

- Customers. Gas gathered and processed through the Hilight system is from numerous third-party customers, with the six largest producers providing 79% of the system throughput during the year ended December 31, 2016.

- Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse Counties, Wyoming.

- Delivery points. The Hilight plant delivers residue into our MIGC transmission line (see Transportation within these Items 1 and 2). Hilight is not connected to an active NGL pipeline, resulting in all fractionated NGLs being sold locally through truck and rail loading facilities.

Newcastle gathering system and processing plant

- Customers. Gas gathered and processed through the Newcastle system is from 11 third-party customers, with the largest three producers providing 79% of the system throughput during the year ended December 31, 2016. The largest producer provided 48% of the throughput during the year ended December 31, 2016.

- Supply. The Newcastle gathering system and plant primarily service gas production from the Clareton and Finn-Shurley fields in Weston County, Wyoming. Due to infill drilling and enhanced production techniques, producers have continued to maintain production levels.

- Delivery points. Propane products from the Newcastle plant are typically sold locally by truck, and the butane/gasoline mix products are transported to the Hilight plant for further fractionation. Residue from the Newcastle system is delivered into Black Hills Corporation’s intrastate pipeline for transport, distribution and sale.

Southwest Wyoming

Granger gathering system and processing complex

- Customers. For the year ended December 31, 2016, 89% of the Granger complex throughput was from five third-party customers and 2% was from Anadarko.

- Supply. The Granger complex is supplied by the Moxa Arch and the Jonah and Pinedale Anticline fields. The Granger gas gathering system had 593 active receipt points as of December 31, 2016.

- Delivery points. The residue from the Granger complex can be delivered to the following major pipelines:

CIG;
Berkshire Hathaway Energy’s Kern River pipeline (“Kern River pipeline”) via a connect with Tesoro Logistics LP’s (“Tesoro”) Rendezvous pipeline (“Rendezvous pipeline”);
Questar Pipeline Company’s pipeline (“Questar pipeline”);
Questar Overthrust Pipeline;
The Williams Companies, Inc.’s Northwest Pipeline (“NWPL”);
our OTTCO pipeline; and
our Mountain Gas Transportation LLC pipeline.

The NGLs have market access to Enterprise Products Partners LP's ("Enterprise") Mid-America Pipeline Company pipeline ("MAPL"), which terminates at Mont Belvieu, Texas, as well as to local markets.

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Red Desert gathering system and processing complex

- Customers. For the year ended December 31, 2016, 61% of the Red Desert complex throughput was from six third-party customers and 7% was from Anadarko.

- Supply. The Red Desert complex gathers, compresses, treats and processes natural gas and fractionates NGLs produced from the eastern portion of the Greater Green River Basin, providing service primarily to the Red Desert and Washakie Basins.

- Delivery points. Residue from the Red Desert complex is delivered to CIG and WIC, while NGLs are delivered to MAPL, as well as to truck and rail loading facilities.

Rendezvous gathering system

- Customers. Tesoro and Anadarko are the only firm customers on the Rendezvous gathering system. To the extent capacity on the system is not used by those customers, it is available to third parties under interruptible agreements.

- Supply and delivery points. The Rendezvous gathering system provides high pressure gathering service for gas from the Jonah and Pinedale Anticline fields and delivers to our Granger plant, as well as Tesoro's Blacks Fork gas processing plant, which connects to the Questar pipeline, NWPL and the Kern River pipeline via the Rendezvous pipeline.

Overview - Rocky Mountains - Colorado and Utah

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
Colorado	DJ Basin complex (1)	Gathering, Processing & Treating	9	919	118	264,044	2	3,205
Utah	Chipeta (2)	Processing	4	980	18	84,007	—	—
Utah	Clawson	Gathering & Treating	2	20 (3)	5	6,310	1	31
Utah	Helper	Gathering & Treating	3	25 (3)	11	13,475	1	130
Total			18	1,944	152	367,836	4	3,366

(1) The DJ Basin complex includes the Platte Valley, Fort Lupton, Fort Lupton JT, Hambert JT, and Lancaster Trains I and II processing plants, the Platteville amine treating plant, and the Wattenberg gathering system.
(2) We are the managing member of and own a 75% interest in Chipeta. Chipeta owns the Chipeta processing complex and the Natural Buttes refrigeration plant.
(3) At current carbon dioxide levels and operating conditions.

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Rocky Mountains - Colorado

DJ Basin gathering system, treating facility and processing complex

- Customers. Anadarko is the largest customer with 70% of the DJ Basin complex throughput for the year ended December 31, 2016. The balance of the throughput was from various third-party customers, with the largest providing 15% of the throughput.

- Supply. There were 2,598 active receipt points connected to the DJ Basin complex as of December 31, 2016. The DJ Basin complex is primarily supplied by the Wattenberg field, in which Anadarko controls 749,000 gross acres. Anadarko drilled 97 wells and completed 204 wells during the year ended December 31, 2016.

- Delivery points. As of December 31, 2016, the DJ Basin complex had the following delivery points for gas not processed within the DJ Basin complex:

Anadarko’s Wattenberg plant inlet; and
Various interconnections with DCP Midstream LP’s (“DCP”) gathering and processing system.

The DJ Basin complex is connected to CIG and Xcel Energy’s residue pipelines for natural gas residue takeaway and to Overland Pass Pipeline Company LLC’s pipeline and FRP’s pipeline for NGL takeaway. In addition, the NGL fractionator at the Platte Valley plant and associated truck-loading facility provides access to local NGL markets.

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Rocky Mountains - Utah

Chipeta processing complex

- Customers. Anadarko is the largest customer at Chipeta with 77% of the system throughput for the year ended December 31, 2016. The balance of throughput during the year ended December 31, 2016 was from 9 third-party customers.

- Supply. The Chipeta complex is well positioned to access Anadarko and third-party production in the Uinta Basin where Anadarko controls 255,000 gross acres. Chipeta's inlet is connected to Anadarko's Natural Buttes gathering system, the Questar pipeline and Three Rivers Gathering, LLC's system, which is owned by Ute Energy and another third party.

- Delivery points. The Chipeta plant delivers NGLs to MAPL, which provides transportation through Enterprise's Seminole pipeline ("Seminole pipeline") and TEP's pipeline in West Texas and ultimately to the NGL fractionation and storage facilities in Mont Belvieu, Texas. The Chipeta plant has residue gas delivery points through the following pipelines delivering to markets throughout the Rockies and Western United States:

CIG;
Questar pipeline; and
WIC.

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Clawson gathering system and treating facility

- Customers. Anadarko is the only shipper on the Clawson gathering system.

- Supply. The Clawson Springs field covers 7,600 gross acres and produces primarily from the Ferron Coal play.

- Delivery points. The Clawson gathering system delivers into the Questar pipeline. The Questar pipeline provides transportation to regional markets in Wyoming, Colorado and Utah and also delivers into the Kern River pipeline, which provides transportation to markets in the Western United States, primarily California.

Helper gathering system and treating facility

- Customers. Anadarko is the only shipper on the Helper gathering system.

- Supply. The Helper and the Cardinal Draw fields are Anadarko-operated coal-bed methane developments on the southwestern edge of the Uinta Basin that produce from the Ferron Coal play. Anadarko owns 19,000 gross acres in the Helper field and 16,000 gross acres in the Cardinal Draw field.

- Delivery points. The Helper gathering system delivers into the Questar pipeline. The Questar pipeline provides transportation to regional markets in Wyoming, Colorado and Utah and also delivers into the Kern River pipeline, which provides transportation to markets in the Western United States, primarily California.

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Overview - North-central Pennsylvania

Location	Asset	Type	Compressors	Compression Horsepower	Gathering Systems	Pipeline Miles
North-central Pennsylvania	Non-Operated Marcellus (1)	Gathering	31	81,400	2	531
North-central Pennsylvania	Anadarko-Operated Marcellus (2)	Gathering	5	6,900	3	142
Total			36	88,300	5	673

(1) WES owns a 33.75% interest in the Non-Operated Marcellus Interest gathering systems, with a third party serving as the operator.

(2) WES owns a 33.75% interest in the Anadarko-Operated Marcellus Interest gathering systems, with Anadarko serving as the operator.

Marcellus gathering systems

- Customers. As of December 31, 2016, in addition to Anadarko, the Non-Operated Marcellus Interest gathering systems had seven priority shippers on its Rome gathering system and eight priority shippers on its Liberty gathering system. Also as of December 31, 2016, in addition to Anadarko, the Anadarko-Operated Marcellus Interest gathering systems had six priority shippers. For the year ended December 31, 2016, Anadarko represented 18% and 43% of throughput on the Non-Operated Marcellus Interest gathering systems and the Anadarko-Operated Marcellus Interest gathering systems, respectively. Capacity not used by priority shippers is available to third parties.

- Supply and delivery points. As of December 31, 2016, Anadarko had a working interest in over 533,000 gross acres within the Marcellus shale. On December 21, 2016, Anadarko announced it had agreed to sell its operated and non-operated upstream assets and operated midstream assets (excluding the Partnership's interests) in the Marcellus shale to a third party, including approximately 195,000 net acres. The transaction is expected to close in the first quarter of 2017, subject to standard closing conditions and adjustments. The Non-Operated Marcellus Interest gathering systems have access to Transcontinental Gas Pipeline Company, LLC's pipeline ("TRANSCO"), Tennessee Gas Pipeline Company, LLC's pipeline and Millennium Pipeline Company, LLC's pipeline. The Anadarko-Operated Marcellus Interest gathering systems have access to TRANSCO.

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Overview - Texas

Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Processing / Treating Capacity (MBbls/d)	Compressors (1)	Compression Horsepower (1)	Gathering Systems	Pipeline Miles
East Texas	Mont Belvieu JV (2)	Processing	2	—	170	—	—	—	—
South Texas	Brasada complex	Gathering, Processing & Treating	3	200	15	14	30,450	1	57
South Texas	Springfield system (3)	Gathering and Treating	3	—	75	107	172,216	2	811
West Texas	Haley	Gathering	—	—	—	10	15,300	1	178
West Texas	DBM complex (4)	Gathering, Processing & Treating	5	700	18	84	149,000	1	357
West Texas	DBJV system (5)	Gathering & Treating	9	360	6	50	65,838	1	577
Total			22	1,260	284	265	432,804	6	1,980

(1) Includes owned, rented and leased compressors and compression horsepower.
(2) We own a 25% interest in the Mont Belvieu JV, which owns two NGL fractionation trains. A third party serves as the operator.
(3) We own a 50.1% interest in the Springfield system and serve as the operator.
(4) Excludes 1,400 gpm of amine treating capacity at the DBM complex. Train VI is currently under construction. See Assets Under Development below.
(5) We own a 50% interest in the DBJV system and serve as the operator.

East Texas

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Mont Belvieu JV fractionation trains

- Customers. The Mont Belvieu JV does not directly contract with customers, but rather is allocated volumes from Enterprise based on the available capacity of the other trains at Enterprise's NGL fractionation complex in Mont Belvieu, Texas.

- Supply and delivery points. Enterprise receives volumes at its fractionation complex in Mont Belvieu, Texas via a large number of pipelines that terminate there, including the Seminole pipeline, Skelly-Belvieu Pipeline Company, LLC's pipeline, TEP and Enterprise's Panola Pipeline, in which Anadarko has a 15% equity interest. Individual NGLs are delivered to end users either through customer-owned pipelines that are connected to nearby petrochemical plants or via export terminal.

South Texas

On January 12, 2017, Anadarko announced it agreed to sell its Eagleford shale upstream assets to third parties, including approximately 155,000 net acres. The transaction is expected to close in the first quarter of 2017, subject to customary closing conditions and adjustments.

Brasada gathering system, stabilization and treating facility and processing complex

- Customers. Anadarko provides 100% of the throughput to the Brasada complex. Anadarko delivers gas and NGLs to the plant on behalf of itself and its upstream joint interest owners.

- Supply. Brasada is supplied from Anadarko's production in the Eagleford shale, in which Anadarko controlled 345,000 gross acres. As noted above, in January 2017, Anadarko announced the sale of its Eagleford shale upstream assets to third parties.

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- Delivery points. The facility delivers residue gas into the Eagle Ford Midstream system operated by NET Midstream, LLC. It delivers stabilized condensate into Plains All American Pipeline and NGLs into the South Texas NGL Pipeline System operated by Enterprise.

Springfield gathering system, stabilization facility and storage

- Customers. Anadarko's production represented 49% of the Springfield gas gathering system's throughput, and 47% of the Springfield oil gathering system's throughput for the year ended December 31, 2016. The remaining throughput was attributable to three third-party producers for the gas gathering system and the oil gathering system.

- Supply. Supply of gas and oil comes from Anadarko's production in the Eagleford shale, in which Anadarko controlled 345,000 gross acres. As noted above, in January 2017, Anadarko announced the sale of its Eagleford shale upstream assets to third parties.

- Delivery points. The gas gathering system delivers rich gas to our Brasada complex and to processing plants operated by Enterprise, Energy Transfer Partners, LP ("ETP") and Kinder Morgan, Inc. The oil gathering system has delivery points to Plains All American Pipeline, Kinder Morgan, Inc.'s Double Eagle Pipeline, Hilcorp Energy Company's Harvest Pipeline and NuStar Energy's Pipeline.

West Texas

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Haley gathering system

- Customers. Anadarko’s production represented 83% of the Haley gathering system’s throughput for the year ended December 31, 2016. The remaining throughput was attributable to two third-party producers.

- Supply. As of December 31, 2016, Anadarko held an interest in over 580,000 gross acres in the greater Delaware Basin, a portion of which is gathered by the Haley gathering system.

- Delivery points. The Haley gathering system provides both lean and rich gas gathering service. The lean service delivery point is into Enterprise GC, LLC’s pipeline for ultimate delivery into ETP’s Oasis pipeline (the “Oasis pipeline”). The rich service system delivery point is into a high pressure gathering line (the “Avalon Express pipeline”), which is part of our DBJV system. The Avalon Express pipeline can deliver gas into either the Bone Spring Gas Processing plant (the “Bone Spring plant”) or the Mi Vida Gas Processing plant (the “Mi Vida plant”), both of which are partially owned by Anadarko. Downstream pipelines at the plant tailgates include the Oasis and Transwestern pipelines at the Bone Spring plant and the Oasis pipeline at the Mi Vida plant. These downstream pipelines provide transportation to both the Waha Hub and Houston Ship Channel markets.

DBM gathering system, treating facility and processing complex. The DBM complex includes 700 MMcf/d of cryogenic processing capacity, 1,400 gpm of amine treating capacity and a 357-mile rich gas gathering system, which has both high and low pressure segments. See Assets Under Development within these Items 1 and 2.

- Customers. Gas gathered and processed through the DBM complex is primarily from third-party producers, with the three largest producers providing 46% of the system throughput for the year ended December 31, 2016.

- Supply. Supply of gas and NGLs for the complex comes from production from the Delaware Sands, Avalon Shale, Bone Spring and Wolfcamp formations in the Delaware Basin portion of the Permian Basin. Anadarko holds an interest in over 580,000 gross acres within the Delaware Basin.

- Delivery points. Residue gas produced at the facility is delivered to an interconnect with the El Paso Natural Gas pipeline. NGL production is delivered into both the Sand Hills pipeline and Lone Star NGL LLC’s pipeline.

DBJV gathering and treating facility. The DBJV gathering system consists of 577 miles of low pressure and high pressure gas gathering lines located in Loving, Ward, Winkler and Reeves Counties, Texas.

- Customers. Anadarko’s production represented 80% of the DBJV system’s throughput for the year ended December 31, 2016. The remaining throughput was attributable to one third-party producer.

- Supply. The system gathers lean Penn gas, as well as liquids-rich Bone Spring, Avalon and Wolfcamp gas.

- Delivery points. Avalon, Bone Spring and Wolfcamp gas is dehydrated, compressed and delivered to both the Bone Spring plant and the Mi Vida plant for processing, while lean Penn gas is delivered into Enterprise GC, LP’s pipeline. Residue gas from the Bone Spring and Mi Vida plants is delivered into the Oasis pipeline or Transwestern pipeline.

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TRANSPORTATION

Overview

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Location	Asset	Type	Compressors / Pump Stations	Operational Horsepower	Pipeline Miles
Northeast Wyoming	MIGC [(1)]	Gas	3	6,660	240
Southwest Wyoming	OTTCO	Gas	1	3,174	217
Utah	GNB NGL [(1)]	NGL	—	—	32
Colorado, Kansas, Oklahoma	White Cliffs [(1)] [(2)]	Oil	24	33,800	1,054
Colorado, Oklahoma, Texas	FRP [(1)] [(3)]	NGL	6	12,000	447
Texas, Oklahoma	TEG [(3)]	NGL	19	1,895	117
Texas	TEP [(1)] [(3)]	NGL	12	27,000	593
Texas	Ramsey Residue Lines [(1)]	Gas	—	—	18
Total			65	84,529	2,718

(1) MIGC, GNB NGL, White Cliffs, FRP, TEP and the Ramsey Residue Lines (at the DBM complex) are regulated by FERC.
(2) We own a 10% interest in the White Cliffs pipeline, which is operated by a third party.
(3) We own a 20% interest in TEG and TEP and a 33.33% interest in FRP. All three systems are operated by third parties.

Rocky Mountains - Northeast Wyoming

MIGC transportation system

- Customers. Anadarko is the largest firm shipper on the MIGC system, with 89% of the throughput for the year ended December 31, 2016. The remaining throughput on the MIGC system was from 16 third-party shippers. MIGC is certificated for 175 MMcf/d of firm transportation capacity.

- Supply. MIGC receives gas from various coal-bed methane gathering systems in the Powder River Basin and the Hilight system, as well as from WBI Energy Transmission, Inc. on the north end of the transportation system.

- Delivery points. MIGC volumes can be redelivered to the hub in Glenrock, Wyoming, which has access to the following interstate pipelines:

CIG;
TIGT; and
WIC.

Volumes can also be delivered to Cheyenne Light Fuel & Power and several industrial users.

Rocky Mountains - Southwest Wyoming

OTTCO transportation system

- Customers. For the year ended December 31, 2016, 11% of OTTCO’s throughput was from Anadarko. The remaining throughput on the OTTCO transportation system was from two third-party shippers. Revenues on the OTTCO transportation system are generated from contract demand charges and volumetric fees paid by shippers under firm and interruptible gas transportation agreements.

Supply and delivery points. Supply points to the OTTCO transportation system include approximately 50 wellheads, the Granger complex and ExxonMobil Corporation's Shute Creek plant, which are supplied by the eastern portion of the Greater Green River Basin, the Moxa Arch and the Jonah and Pinedale Anticline fields. Primary delivery points include the Red Desert complex, two third-party industrial facilities and an inactive interconnection with the Kern River pipeline.

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Rocky Mountains - Utah

GNB NGL pipeline

- Customers. Anadarko was the only shipper on the GNB NGL pipeline for the year ended December 31, 2016.

- Supply. The GNB NGL pipeline receives NGLs from Chipeta's gas processing facility and Tesoro's Stagecoach/Iron Horse gas processing complex.

- Delivery points. The GNB NGL pipeline delivers NGLs to MAPL, which provides transportation through the Seminole pipeline and TEP in West Texas, and ultimately to NGL fractionation and storage facilities in Mont Belvieu, Texas.

Rocky Mountains - Colorado

White Cliffs pipeline

- Customers. The White Cliffs pipeline had multiple committed shippers, including Anadarko, during the year ended December 31, 2016. In addition, other parties may ship on the White Cliffs pipeline at FERC-based rates. The White Cliffs dual pipeline system provides 150 MBbls/d of crude takeaway capacity from Platteville, Colorado to Cushing, Oklahoma. White Cliffs is currently undergoing an expansion project that will increase the pipeline's capacity to approximately 215 MBbls/d. This expansion project is scheduled to be completed early in the second quarter of 2017.

- Supply. The White Cliffs pipeline is supplied by production from the DJ Basin.

- Delivery points. The White Cliffs pipeline delivery point is SemCrude's storage facility in Cushing, Oklahoma, a major crude oil marketing center, which ultimately delivers to Gulf Coast and mid-continent refineries. At the point of origin, it has a 330,000-barrel storage facility adjacent to a truck-unloading facility.

Texas

TEFR Interests

- Front Range Pipeline. FRP provides takeaway capacity from the DJ Basin in Northeast Colorado. FRP has receipt points at gas plants in Weld County, Colorado (including our Lancaster plant, which is within the DJ Basin complex) (see Rocky Mountains—Colorado and Utah within these Items 1 and 2). FRP connects to TEP near Skellytown, Texas. During the year ended December 31, 2016, FRP had multiple committed shippers, including Anadarko, and provides capacity for other shippers at the posted FERC tariff rate.

- Texas Express Gathering. TEG consists of two NGL gathering systems that provide plants in North Texas, the Texas panhandle and West Oklahoma with access to NGL takeaway capacity on TEP. TEG had one committed shipper during the year ended December 31, 2016.

- Texas Express Pipeline. TEP delivers to NGL fractionation and storage facilities in Mont Belvieu, Texas. At Skellytown, Texas, TEP is supplied with NGLs from other pipelines including FRP and MAPL. TEP had multiple committed shippers, including Anadarko, during the year ended December 31, 2016 and provides capacity for other shippers at the posted FERC tariff rates.

Ramsey Residue Lines. The Ramsey Residue Lines extend from the DBM complex tailgate to the south and to the north, with both lines connecting with Kinder Morgan Inc.'s interstate pipeline system. These lines transport residue gas from the DBM complex to interstate markets and are FERC-regulated pipelines. See DBM gathering system, treating facility and processing complex within these Items 1 and 2.

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Assets Under Development

In addition to significant expansion projects at the DBJV system, we currently have the following significant projects scheduled for completion in 2017 and 2018 in West Texas. See Capital expenditures, under Part II, Item 7 of this Form 10-K.

- DBM Train VI: The 200 MMcf/d cryogenic train is under construction and is expected to be completed during the fourth quarter of 2017. The DBM complex will have 900 MMcf/d processing capacity upon completion.
- Mentone gas plant: We have sanctioned a new gas processing plant which will be located in Loving County, Texas. This plant will have connections to the DBJV system in West Texas. Engineering and procurement of equipment has begun and the construction of the initial cryogenic trains (Mentone Trains I and II) is expected to begin during the fourth quarter of 2017.
- Produced-water disposal systems: The River Reeves and Silvertip systems located in Reeves County and Loving County, Texas, respectively, are currently under construction with expected in-service dates during the second quarter of 2017. The River Reeves and Silvertip systems are expected to have produced-water disposal capacities of 30 MBbls/d and 60 MBbls/d, respectively. The two facilities currently have contracts in place with a subsidiary of Anadarko.

COMPETITION

The midstream services business is very competitive. Our competitors include other midstream companies, producers, and intrastate and interstate pipelines. Competition is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. However, a substantial portion of the throughput volumes on a majority of our systems are owned or controlled by Anadarko. In addition, Anadarko has dedicated future production to us from its acreage surrounding the Wattenberg, Haley, Helper and Clawson gathering systems. We believe that our assets that are located outside of the dedicated areas are geographically well positioned to retain and attract third-party volumes due to our competitive rates.
We believe the primary advantages of our assets are their proximity to established and/or future production, and the service flexibility they provide to producers. We believe we can provide the services that producers and other customers require to connect, gather and process their natural gas efficiently, at competitive and flexible contract terms.

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Gathering Systems and Processing Plants

The following table summarizes the primary competitors for our gathering systems and processing plants at December 31, 2016.

System	Competitor(s)
Anadarko-Operated Marcellus Interest gathering systems	ETP and National Fuel Gas Midstream Corporation
Bison facility	Thunder Creek Gas Services, LLC and Fort Union (treating only)
Brasada complex	Enterprise, ETP, Targa Resources, LP, Kinder Morgan, Inc., Plains All American Pipeline and Howard Energy Partners
Chipeta complex	Tesoro and Kinder Morgan, Inc.
DBJV system	ETP, Outrigger Midstream, Enterprise GC, LP, EagleClaw Midstream Ventures LLC, Enlink Midstream, LP and Vaquero Midstream LLC
DBM complex	ETP, Outrigger Midstream, Enterprise GC, LP, EagleClaw Midstream Ventures LLC, Enlink Midstream, LP and Vaquero Midstream LLC
DJ Basin complex	DCP and AKA Energy Group, LLC
Fort Union	Bison treating facility (carbon dioxide treating services only), MIGC, Thunder Creek Gas Services, LLC and TransCanada Corporation
Granger complex	Williams Field Services, Enterprise/Jonah Gas Gathering Company and Tesoro
Haley system	ETP, Outrigger Midstream, Enterprise GC, LP
Helper and Clawson systems	XTO Energy
Hilight system	DCP, ONEOK Gas Gathering Company, Thunder Creek Gas Services, LLC, Crestwood-Access, Tallgrass Energy Partners, LP and Agave Energy Company
Mont Belvieu JV	Targa Resources LP, Phillips 66, Lone Star NGL LLC and ONEOK Partners, LP
Newcastle system	DCP
Non-Operated Marcellus Interest gathering systems	ETP
Red Desert complex	Williams Field Services and Tesoro
Rendezvous	No significant direct competition
Springfield system	Enterprise, ETP, Targa Resources, LP, Kinder Morgan, Inc., Plains All American Pipeline, Southcross Energy Partners, L.P., Williams Field Services and Howard Energy Partners

Transportation

MIGC competes with other pipelines that service the regional market and transport gas volumes from the Powder River Basin to Glenrock, Wyoming. MIGC competitors seek to attract and connect new gas volumes throughout the Powder River Basin, including certain of the volumes currently being transported on the MIGC pipeline. Competitive factors include commercial terms, available capacity, fuel efficiencies, the interconnected pipelines and gas quality issues. MIGC's major competitors are Thunder Creek Gas Services, LLC, TransCanada Corporation's Bison pipeline and the Fort Union gathering system. The GNB NGL Pipeline's major competitor is Tesoro. The White Cliffs pipeline faces direct competition from the Saddlehorn pipeline, in which Anadarko is a 20% interest owner, and the Grand Mesa pipeline. The Saddlehorn pipeline transports crude oil from the DJ Basin and the broader Rocky Mountain area to Cushing, Oklahoma. White Cliffs pipeline shippers can also sell crude oil in local markets or ship crude via rail services rather than via pipeline to Cushing, Oklahoma. The TEFR Interests compete with the Sand Hills pipeline, West Texas LPG Pipeline LP's pipeline, Lone Star NGL LLC's West Texas System, Overland Pass Pipeline Company LLC's pipeline and the Seminole pipeline. The OTTCO transportation system faces no direct competition. The Ramsey Residue Lines face competition from ETP, Enterprise and Kinder Morgan, Inc.

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REGULATION OF OPERATIONS

Safety and Maintenance

Many of the pipelines we use to gather and transport oil, natural gas and NGLs are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the Department of Transportation pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (the "NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (the "HLPSA"), with respect to NGLs and oil. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thicknesses, design pressures, maximum allowable operating pressures ("MAOP"), pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect high consequence areas ("HCAs"), where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. Past operation of our pipelines with respect to these NGPSA and HLPSA requirements has not resulted in the incurrence of material costs; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs that could have a material adverse effect on our results of operations or financial position.

The NGPSA and HLPSA were amended by the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"), which increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. More recently, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (the "2016 Pipeline Safety Act") empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing.

The adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on our results of operations. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register is uncertain given the recent change in presidential administrations. Additionally, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for gas pipelines in newly defined "moderate consequence areas" that contain as few as five dwellings within a potential impact area; requiring gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA's integrity management requirements for gas pipelines and also require consideration of seismicity in evaluating threats to pipelines. New laws or regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. In addition, while states are largely preempted by federal law from regulating pipeline safety for interstate lines, most are certified by PHMSA to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In practice, because states can adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines, states vary considerably in their authority and capacity to address pipeline safety. Historically, our intrastate pipeline safety compliance costs have not had a material adverse effect on our operations; however, there can be no assurance that such costs will not be material in the future.

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We are also subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. Furthermore, we and the entities in which we own an interest are subject to regulations that (i) require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and citizens and (ii) are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals.
See Risk Factor, "Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation" under Part I, Item 1A of this Form 10-K for further discussion on pipeline safety standards.

Interstate Natural Gas Pipeline Regulation

Regulation of pipeline transportation services may affect certain aspects of our business and the market for our products and services.
The operations of our MIGC pipeline and the Ramsey Residue Lines are subject to regulation by FERC under the Natural Gas Act of 1938 (the "NGA"). Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as the following:

- rates, services, and terms and conditions of service;
- types of services that may be offered to customers;
- certification and construction of new facilities;
- acquisition, extension, disposition or abandonment of facilities;
- maintenance of accounts and records;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for transportation services;
- relationships between affiliated companies involved in certain aspects of the natural gas business;
- initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

Natural gas companies are prohibited from charging rates that have been determined not to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

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The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC's jurisdiction over rates, existing rates may be challenged by complaint or by action of FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. The outcome of any successful complaint or protest against our rates could have an adverse impact on revenues associated with providing transportation service. For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership owners double-recovering their income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. There is not likely to be a definitive resolution of these issues for some time, and the ultimate outcome of this proceeding is not certain and could result in changes going forward to the FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our FERC-regulated interstate pipelines could be affected to the extent new rates or changes to its existing rates are proposed, or if any such rates are subject to complaint or challenged by the FERC, which could cause the rates and revenues for our FERC-regulated pipelines to be adversely affected.

Interstate natural gas pipelines regulated by FERC are also required to comply with numerous regulations related to standards of conduct, market transparency, and market manipulation. FERC's standards of conduct regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates (unless FERC has granted a waiver of such standards). FERC's market oversight and transparency regulations require annual reports of purchases or sales of natural gas meeting certain thresholds and criteria and certain public postings of information on scheduled volumes. FERC's market manipulation regulations make it unlawful for any entity, directly or indirectly in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to engage in fraudulent conduct. FERC has authority to impose civil penalties for violations of these statutes and regulations, up to $1.0 million per day per violation. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Interstate Liquids Pipeline Regulation

Regulation of interstate liquids pipeline services may affect certain aspects of our business and the market for our products and services. Our GNB NGL Pipeline provides service as a common carrier under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. FERC regulation requires that interstate liquid pipeline rates, including rates for transportation of NGLs, be filed with FERC and that these rates be "just and reasonable" and not unduly discriminatory. Rates of interstate NGL pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, an NGL pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.

The Interstate Commerce Act permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. The just and reasonable rate used to calculate refunds cannot be lower than the last tariff rate approved as just and reasonable. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for charges in excess of a just and reasonable rate for a period of up to two years prior to the filing of a complaint. Finally, the outcome of the FERC policy regarding income tax allowance described above would also apply to our pipelines regulated under the Interstate Commerce Act.

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Natural Gas Gathering Pipeline Regulation

Regulation of gathering pipeline services may affect certain aspects of our business and the market for our products and services. Natural gas gathering facilities are exempt from the jurisdiction of FERC. We believe that our gathering pipelines meet the traditional tests that FERC has used to determine that a pipeline is not subject to FERC jurisdiction, although FERC has not made any determinations with respect to the jurisdictional status of any of our pipelines other than MIGC and the Ramsey Residue Lines. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. FERC makes jurisdictional determinations on a case-by-case basis. Our natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Our natural gas gathering operations also may be or become subject to additional safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Our natural gas gathering operations are subject to ratable take and common purchaser statutes in most of the states in which we operate. These statutes generally require our gathering pipelines to take natural gas without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal remedies. To date, there has been no adverse effect to our systems due to these regulations.

FERC’s anti-manipulation rules apply to non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but only to the extent such transactions do not have a “nexus” to jurisdictional transactions. In addition, FERC’s market oversight and transparency regulations may also apply to otherwise non-jurisdictional entities to the extent annual purchases and sales of natural gas reach a certain threshold. FERC’s civil penalty authority, described above, would apply to violations of these rules.

Intrastate Pipeline Regulation

Regulation of intrastate pipeline services may affect certain aspects of our business and the market for our products and services. Intrastate natural gas and liquids transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate pipeline operators within the state on a comparable basis, we believe that the regulation of intrastate transportation in any states in which we operate will not disproportionately affect our operations.

In the event any of our intrastate pipelines offer natural gas transportation services under Section 311 of the Natural Gas Policy Act of 1978, such pipelines will be required to meet certain quarterly reporting requirements providing detailed transaction information which could be made public. Such pipelines will also be subject to periodic rate review by FERC. In addition, FERC’s anti-manipulation, market oversight, and market transparency regulations may extend to intrastate natural gas pipelines although they may otherwise be non-jurisdictional, and FERC's civil penalty authority, described above, would apply to violations of these rules.

Financial Reform Legislation

For a description of financial reform legislation that may affect our business, financial condition and results of operations, read Risk Factors under Part I, Item 1A of this Form 10-K for more information.

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ENVIRONMENTAL MATTERS

Our business operations are subject to numerous federal, regional, state, tribal, and local environmental laws and regulations. The more significant of these existing environmental laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the Clean Air Act, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the U.S. Environmental Protection Agency (the “EPA”) has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas (“GHG”) emissions.
- the Federal Water Pollution Control Act, also known as the Federal Clean Water Act, which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemakings as protected waters of the United States.
- the Oil Pollution Act of 1990, which subjects owners and operators of onshore facilities and pipelines to liability for removal costs and damages arising from an oil spill in waters of the United States.
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- the Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes.
- the Safe Drinking Water Act, which ensures the quality of the nation’s public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources.
- the Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories.
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas.
- the National Environmental Policy Act, which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment.

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These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. See the following risk factors under Part I, Item 1A of this Form 10-K for further discussion on ozone standards, climate change, including methane or other GHG emissions, hydraulic fracturing and other regulations related to environmental protection: “We are subject to stringent and comprehensive environmental laws and regulations that may expose us to significant costs and liabilities,” “The adoption of climate change or other air emissions legislation or regulations restricting emissions of GHGs or other air pollutants could result in increased operating costs and reduced demand for the gathering, processing, compressing, treating and transporting services we provide,” and “Changes in laws or regulations regarding hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and natural gas wells, which could decrease the need for our gathering and processing services.” The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards continue to evolve.

Many states where we operate also have, or are developing, similar environmental laws and regulations governing many of these same types of activities. While the legal requirements imposed under state law may be similar in form to U.S. laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development or expansion of a project or substantially increase the cost of doing business. In addition, environmental laws and regulations, including new or amended legal requirements that may arise to address potential environmental concerns including air and water impacts, are expected to continue to have an increasing impact on our operations.

We have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not have a material adverse effect on our business, financial condition, results of operations, or cash flows in the future, or that new or more stringently applied existing laws and regulations will not materially increase the cost of doing business. Although we are not fully insured against all environmental and occupational health and safety risks, and our insurance does not cover any penalties or fines that may be issued by a governmental authority, we maintain insurance coverage that we believe is sufficient based on our assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations, as well as claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to us.

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TITLE TO PROPERTIES AND RIGHTS-OF-WAY

Our real property is classified into two categories: (1) parcels that we own in fee title and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located is held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessor. We or affiliates of ours have leased or owned these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership of such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

Some of the leases, easements, rights-of-way, permits and licenses transferred to us by Anadarko required the consent of the grantor of such rights, which in certain instances is a governmental entity. Our general partner has obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary to enable us to operate our business in all material respects. With respect to any remaining consents, permits or authorizations that have not been obtained, we have determined these will not have material adverse effect on the operation of our business should we fail to obtain such consents, permits or authorization in a reasonable time frame.

Anadarko may hold record title to portions of certain assets as we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals as needed. Such consents and approvals would include those required by federal and state agencies or other political subdivisions. In some cases, Anadarko temporarily holds record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, cause its affiliates to retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from Anadarko holding the title to any part of such assets subject to future conveyance or as our nominee.

EMPLOYEES

The officers of our general partner manage our operations and activities under the direction and supervision of our Board of Directors. As of December 31, 2016, Anadarko employed 392 people who provided direct support to our field operations. All of these employees are deemed jointly employed by Anadarko and our general partner under the services and secondment agreement between our general partner and Anadarko. None of these employees are covered by collective bargaining agreements, and Anadarko considers its employee relations to be good. We have separately contracted with Anadarko under the omnibus agreement for general and administrative support for our operations.

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Item 1A. Risk Factors

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this Form 10-K, and may from time to time make in other public filings, press releases and statements by management, forward-looking statements concerning our operations, economic performance and financial condition. These forward-looking statements include statements preceded by, followed by or that otherwise include the words “believes,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “target,” “goal,” “plans,” “objective,” similar expressions or variations on such expressions. These statements discuss future expectations, contain projections of results of operations or financial condition or include other “forward-looking” information. Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurance that such expectations will prove to have been correct. These forward-looking statements involve risks and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following:

- our ability to pay distributions to our unitholders;
- our and Anadarko’s assumptions about the energy market;
- future throughput (including Anadarko production) which is gathered or processed by or transported through our assets;
- our operating results;
- competitive conditions;
- technology;
- the availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;
- the supply of, demand for, and price of, oil, natural gas, NGLs and related products or services;
- our ability to mitigate exposure to the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts through the extension of our commodity price swap agreements with Anadarko, or otherwise;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, internationally, domestically or in the jurisdictions in which we are doing business;
- federal, state and local laws, including those that limit Anadarko and other producers’ hydraulic fracturing or other oil and natural gas operations;
- environmental liabilities;

- legislative or regulatory changes, including changes affecting our status as a partnership for federal income tax purposes;

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- changes in the financial or operational condition of Anadarko;
- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use our RCF;
- our ability to repay debt;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;
- our ability to acquire assets on acceptable terms from Anadarko or third parties, and Anadarko's ability to generate an inventory of assets suitable for acquisition;
- non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko;
- the timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below and elsewhere in this Item 1A, under the caption Critical Accounting Estimates included under Part II, Item 7 of this Form 10-K, and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this Form 10-K 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.

Common units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. We urge you to carefully consider the following risk factors together with all of the other information included in this Form 10-K in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially and adversely affected. In such case, the trading price of the common units could decline and you could lose all or part of your investment.

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RISKS INHERENT IN OUR BUSINESS

We are dependent on Anadarko for a substantial portion of the natural gas, crude oil and NGLs that we gather, treat, process and/or transport. A material reduction in Anadarko's production that is gathered, treated, processed or transported by our assets would result in a material decline in our revenues and cash available for distribution.

We rely on Anadarko for a substantial portion of the natural gas, crude oil and NGLs that we gather, treat, process and/or transport. For the year ended December 31, 2016, production owned or controlled by Anadarko represented (i) 37% of our natural gas gathering, treating and transportation throughput (excluding equity investment throughput), (ii) 54% of our natural gas processing throughput (excluding equity investment throughput), and (iii) 65% of our crude/NGL gathering, treating and transportation throughput (excluding equity investment throughput). Anadarko may decrease its production in the areas serviced by us and is under no contractual obligation to maintain its production volumes dedicated to us pursuant to the terms of our applicable gathering agreements. The loss of a significant portion of production volumes supplied by Anadarko would result in a material decline in our revenues and our cash available for distribution. In addition, Anadarko may determine that drilling activity in areas other than our areas of operation is strategically more attractive. For example, Anadarko announced it has agreed to sell its operated midstream assets in the Marcellus shale and its upstream assets in the Eagleford shale. A shift in Anadarko's focus away from our areas of operation could result in reduced throughput on our systems and a material decline in our revenues and cash available for distribution.

Because we are substantially dependent on Anadarko as our primary customer and the controlling party of our general partner, any development that materially and adversely affects Anadarko's operations, financial condition or market reputation could have a material and adverse impact on us. Material adverse changes at Anadarko could restrict our access to capital, make it more expensive to access the capital markets or increase the costs of our borrowings.

We are substantially dependent on Anadarko as our primary customer and the controlling party of our general partner and we expect to derive a substantial majority of our revenues from Anadarko for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Anadarko's production, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of Anadarko, some of which are the following:

- the volatility of oil and natural gas prices, which could have a negative effect on the value of Anadarko's oil and natural gas properties, its drilling programs and its ability to finance its operations;
- the availability of capital on favorable terms to fund Anadarko's exploration and development activities;
- a reduction in or reallocation of Anadarko's capital budget, which could reduce the gathering, transportation and treating volumes available to us as a midstream operator, limit our midstream opportunities for organic growth or limit the inventory of midstream assets we may acquire from Anadarko;
- Anadarko's ability to replace its oil and natural gas reserves;
- Anadarko's operations in foreign countries, which are subject to political, economic and other uncertainties;
- Anadarko's drilling and operating risks, including potential environmental liabilities;
- transportation capacity constraints and interruptions;

- adverse effects of governmental and environmental regulation;
- shareholder activism with respect to Anadarko’s stock or activities by non-governmental organizations to restrict the exploration, development and production of oil and natural gas by Anadarko in order to minimize emissions of carbon dioxide, a GHG; and
- adverse effects from current or future litigation.

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Further, we are subject to the risk of non-payment or non-performance by Anadarko, including with respect to our gathering and transportation agreements, our $260.0 million note receivable from Anadarko and our commodity price swap agreements. We cannot predict the extent to which Anadarko’s business would be impacted if conditions in the energy industry were to deteriorate further, nor can we estimate the impact such conditions would have on Anadarko’s ability to perform under our gathering and transportation agreements, note receivable or commodity price swap agreements. Accordingly, any material non-payment or non-performance by Anadarko could reduce our ability to make distributions to our unitholders.

Also, due to our relationship with Anadarko, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairments to Anadarko’s financial condition or adverse changes in its credit ratings. Read Our credit rating downgrade could negatively impact our cost of and ability to access capital in these Risk Factors for a further discussion.

Any material limitations on our ability to access capital as a result of such adverse changes at Anadarko could limit our ability to obtain future financing on favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at Anadarko could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing, or could negatively affect our ability to engage in, expand or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

See Part I, Item 1A in Anadarko’s Form 10-K for the year ended December 31, 2016 (which is not, and shall not be deemed to be, incorporated by reference herein), for a full discussion of the risks associated with Anadarko’s business.

Sustained low natural gas, NGL or oil prices could adversely affect our business.

Sustained low natural gas, NGL or oil prices impact natural gas and oil exploration and production activity levels and can result in a decline in the production of hydrocarbons over the medium to long term, resulting in reduced throughput on our systems. Such a decline also potentially affects the ability of our vendors, suppliers and customers to continue operations. As a result, sustained lower natural gas and crude oil prices could have a material adverse effect on our business, results of operations, financial condition and our ability to pay cash distributions to our unitholders.

In general terms, the prices of natural gas, oil, condensate, NGLs and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. For example, market prices for natural gas have declined substantially from the highs achieved in 2008 and have remained depressed for several years. More recently, uncertain global demand and the increased supply resulting from the rapid development of shale plays throughout North America have contributed significantly to a substantial drop in crude oil prices. Rapid development of the North American shale plays has also increased the supply of natural gas contributing to a substantial drop in natural gas prices. For example, NYMEX West Texas Intermediate oil prices have been volatile and recently ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Also, NYMEX Henry Hub natural gas prices have been volatile and recently ranged from a high of $6.15 per MMBtu in February 2014 to a low of $1.64 per MMBtu in March 2016. Additional factors impacting commodity prices include the following:

- domestic and worldwide economic and geopolitical conditions;
- weather conditions and seasonal trends;
- the ability to develop recently discovered fields or deploy new technologies to existing fields;
- the levels of domestic production and consumer demand, as affected by, among other things, concerns over inflation, geopolitical issues and the availability and cost of credit;

- the availability of imported, or a market for exported, liquefied natural gas;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials, such as in the Rocky Mountains;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;

- the nature and extent of governmental regulation and taxation; and

- the forecasted supply and demand for, and prices of, oil, natural gas, NGLs and other commodities.

We generate distributable cash flow from the above-market component of commodity price swap agreements with Anadarko that are scheduled to expire on December 31, 2017.

As discussed in more detail in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K, for the year ended December 31, 2016, we had commodity price swap agreements in place with Anadarko related to our activities at the DJ Basin complex and Hugoton system at prices that were significantly higher than those that could have been obtained from third parties on the open market. The above-market component of this swap activity is recorded as a cash contribution from Anadarko in the period in which attributable volumes are settled, with all such contributions included in our calculation of distributable cash flows. During 2016, for example, we recorded $45.8 million in cash contributions from Anadarko related to these swaps.

On December 1, 2016, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets at significantly higher prices than those that could have been obtained from third parties on the open market. These swap agreements expire on December 31, 2017.

We may be unable to further renew the swaps with Anadarko for the DJ Basin complex and the MGR assets on similar terms or at all. If such agreements are renewed with Anadarko, they may be renewed at lower prices than those established in the agreements currently in place. In the event that we are unable to renew agreements with Anadarko, we may seek to enter into third-party commodity price swap agreements or similar hedging arrangements. Any such market-based hedging arrangement is likely to be significantly less favorable from a commodity pricing perspective and would likely result in a significant decrease in our distributable cash flow.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of oil and natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes that we gather, process, treat and transport could adversely affect our business and operating results.

The volumes that support our business are dependent on, among other things, the level of production from natural gas and oil wells connected to our gathering systems and processing and treating facilities. This production will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our systems, we must obtain new sources of oil and natural gas. The primary factors affecting our ability to obtain sources of oil and natural gas include (i) the level of successful drilling activity near our systems, (ii) our ability to compete for volumes from successful new wells, to the extent such wells are not dedicated to our systems, and (iii) our ability to capture volumes currently gathered or processed by Anadarko or third parties.

While Anadarko has dedicated production from certain of its properties to us, we have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over Anadarko or other producers or their drilling or production decisions, which are affected by, among other things, the availability and cost of capital, prevailing and projected commodity prices, demand for hydrocarbons, levels of reserves, geological considerations, governmental regulations, the availability of drilling rigs and other production and development costs. Fluctuations in commodity prices can also greatly affect investments by Anadarko and third parties in the development of new oil and natural gas reserves. Declines in oil and natural gas prices have materially reduced exploration, development and production activity and, if sustained, could lead to a further decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our gathering, processing and treating assets.

Because of these factors, even if new oil and natural gas reserves are known to exist in areas served by our assets, producers (including Anadarko) may choose not to develop those reserves. Moreover, Anadarko may not develop the acreage it has dedicated to us. If competition or reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, it could reduce our revenue and impair our ability to make cash distributions to our unitholders.

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We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay announced distributions to holders of our common units.

In order to pay the announced fourth quarter 2016 distribution of $0.86 per unit per quarter, or $3.44 per unit per year, we will require available cash of $182.1 million per quarter, or $728.4 million per year, based on the number of common units, general partner units, IDRs and Series A Preferred units outstanding at February 2, 2017. We may not have sufficient available cash from operating surplus each quarter to enable us to pay distributions at current levels. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the prices of, level of production of, and demand for oil and natural gas;
- the volume of oil and natural gas we gather, compress, process, treat and/or transport;
- the volumes and prices of NGLs and condensate that we retain and sell;
- demand charges and volumetric fees associated with our transportation services;
- the level of competition from other midstream energy companies;
- regulatory action affecting the supply of or demand for oil or natural gas, the rates we can charge, how we contract for services, our existing contracts, our operating costs or our operating flexibility; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including the following:

- our level of capital expenditures;
- our level of operating and maintenance and general and administrative costs;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- our treatment as a flow-through entity for U.S. federal income tax purposes;
- restrictions contained in debt agreements to which we are a party or with respect to any outstanding preferred units; and
- the amount of cash reserves established by our general partner.

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The amount of cash we pay to our general partner under the IDRs increases as we grow our distributions to limited partners. This increased payout to our general partner raises our overall cost of capital which could impact distribution growth.

WGP, through its ownership of our general partner, holds all of our IDRs. While the IDRs provide Anadarko, which indirectly owns an 81.6% limited partner interest in WGP, financial incentive to continue to grow our business over time, 31.8% of our total distributions (excluding distributions paid on Series A Preferred and Class C units) were paid to our general partner as a result of its ownership of our IDRs during the fourth quarter of 2016. As this percentage grows over time, our cost of equity capital will increase. As a result, in the future we may be unable to acquire or construct assets on an accretive basis and further grow our limited partner distributions.

Our credit rating downgrade could negatively impact our cost of and ability to access capital.

As of December 31, 2016, our long-term debt was rated “BBB-” with a stable outlook by S&P, “BBB-” with a stable outlook by Fitch, and “Ba1” with a stable outlook by Moody’s. In February 2016, Moody’s downgraded Anadarko’s senior unsecured ratings from Baa2 to Ba1, with a negative outlook, and downgraded our senior unsecured ratings from Baa3 to Ba1, with a negative outlook, both of which are below investment grade. In September 2016, Moody’s changed the outlook for Anadarko and us from negative to stable. We cannot be assured that our credit rating will not be downgraded further. Any further downgrades in our credit ratings will adversely affect our ability to raise debt in the public debt markets, which could negatively impact our cost of capital and ability to effectively execute aspects of our strategy.
In addition, downgrades could trigger our obligations to provide financial assurance of our performance under certain contractual arrangements. We may be required to post collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements, such as pipeline transportation contracts and NGLs and gas sales contracts. At December 31, 2016, there were $4.9 million in letters of credit or cash provided as assurance of our performance under these type of contractual arrangements with respect to credit-risk-related contingent features. We do not currently have any contracts that automatically trigger collateral posting requirements upon the loss of investment grade ratings.

Our strategies to reduce our exposure to changes in commodity prices may fail to protect us and could negatively impact our financial condition, thereby reducing our cash flows and our ability to make distributions to unitholders.

For the year ended December 31, 2016, 6% of our Adjusted gross margin was generated under percent-of-proceeds and keep-whole arrangements pursuant to which the associated revenues and expenses are directly correlated with the prices of natural gas, oil and NGLs. This percentage may significantly increase as a result of future acquisitions, if any.
We pursue various strategies to seek to reduce our exposure to adverse changes in the prices for natural gas, condensate and NGLs. These strategies will vary in scope based upon the level and volatility of natural gas, condensate and NGL prices and other changing market conditions. We currently have in place commodity price swap agreements with Anadarko expiring in December 2017 to manage a majority of the commodity price risk otherwise inherent in our percent-of-proceeds and keep-whole contracts. To the extent that we engage in price risk management activities such as the commodity price swap agreements, we may be prevented from realizing the full benefits of price increases above the levels set in those agreements. In addition, our commodity price management may expose us to the risk of financial loss in certain circumstances, including if the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements.

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On December 1, 2016, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2017. Upon the expiration of these commodity price swap agreements, we may be unable to renew such agreements with Anadarko on similar terms or at all. If such agreements are renewed with Anadarko, they may be renewed at lower prices than those established in the agreements currently in place. In the event that we are unable to renew agreements with Anadarko, we may seek to enter into third-party commodity price swap agreements or similar hedging arrangements. Any such market-based hedging arrangement is likely to be significantly less favorable from a commodity pricing perspective and would likely expose us to volumetric risk to which we are currently not exposed, because our current commodity price swap agreements with Anadarko are based on our actual volumes.

Additionally, if we are unable to effectively manage the risk associated with our contracts that have commodity price exposure, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

While we do not conduct hydraulic fracturing, our customers do conduct such activities. Hydraulic fracturing is an essential and common practice used by many of our oil and natural gas exploration and production customers to stimulate production of natural gas and oil from dense subsurface rock formations such as shales. Hydraulic fracturing is typically regulated by state oil and natural-gas commissions, but several federal agencies have also asserted regulatory authority over certain aspects of the process. For example, in June 2016, the EPA published an effluent limit guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants. Also, the federal Bureau of Land Management (“BLM”) published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. A Wyoming federal judge struck down this rule in June 2016 finding that the BLM lacked authority to promulgate the rule. That decision is currently being appealed by the federal government.

In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states have adopted or are considering adopting legal requirements that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations, and states could elect to prohibit high-volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

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

Adverse developments in our geographic areas of operation could disproportionately impact our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our business and operations are concentrated in a limited number of producing areas. Due to our limited geographic diversification, adverse operational developments, regulatory or legislative changes, or other events in an area in which we have significant operations could have a greater impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders than they would if our operations were more diversified.

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If Anadarko were to limit transfers of midstream assets to us or if we were to be unable to make acquisitions on economically acceptable terms from Anadarko or third parties, our future growth would be limited. In addition, any acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per-unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per-unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants, including, most notably, Anadarko. A material decrease in such divestitures would limit our opportunities for future acquisitions and could adversely affect our ability to grow our operations and increase our distributions to our unitholders.
If we are unable to make accretive acquisitions from Anadarko or third parties because, among other things, (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) we are unable to obtain financing for these acquisitions on economically acceptable terms, (iii) we are outbid by competitors or (iv) Anadarko lacks assets suitable for us to acquire, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per-unit basis.
Any acquisition involves potential risks, including the following, among other things:

- mistaken assumptions about volumes or the timing of those volumes, revenues or costs, including synergies;
- an inability to successfully integrate the acquired assets or businesses;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management’s and employees’ attention from other business concerns;
- unforeseen difficulties operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

We may not be able to obtain funding on acceptable terms or at all. This may hinder or prevent us from meeting our future capital needs.

Global financial markets and economic conditions have been, and continue to be, volatile, especially for companies involved in the oil and gas industry. The repricing of credit risk and the current relatively weak economic conditions have made, and will likely continue to make, it difficult for some entities to obtain funding. In addition, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to the borrower’s current debt, and reduced, or in some cases, ceased to provide funding to borrowers. Further, we may be unable to obtain adequate funding under our RCF if our lending counterparties become unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that funding will be available if needed and to the extent required on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders.

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Restrictions in the indentures governing our publicly traded notes (collectively, “the Notes”) or the RCF may limit our ability to capitalize on acquisitions and other business opportunities.

The operating and financial restrictions and covenants in the agreements governing the Notes, the RCF and any future financing arrangements could restrict our ability to finance future operations or capital needs or to expand or pursue business activities associated with our subsidiaries and equity investments. The RCF contains, and with respect to the second, fourth and fifth bullets below, the indentures governing the Notes contain, covenants that restrict or limit our ability to do the following:

- incur additional indebtedness or guarantee other indebtedness;
- grant liens to secure obligations other than our obligations under the Notes or RCF or agree to restrictions on our ability to grant additional liens to secure our obligations under the Notes or RCF;
- engage in transactions with affiliates;
- make any material change to the nature of our business from the midstream energy business; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

The RCF also contains various customary covenants, customary events of default and a maximum consolidated leverage ratio as of the end of each quarter (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to Consolidated EBITDA, as defined in the RCF, for the most recent four consecutive fiscal quarters ending on such day) of 5.0 to 1.0, or a consolidated leverage ratio of 5.5 to 1.0 with respect to quarters ending in the 270-day period immediately following certain acquisitions. See Part II, Item 7 of this Form 10-K for a further discussion of the terms of our RCF and Notes.

Debt we owe or incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

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Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Interest rates may increase in the future, whether because of inflation, increased yields on U.S. Treasury obligations or otherwise. In such cases, the interest rates on our floating rate debt, including amounts outstanding under our RCF, would increase. If interest rates rise, our future financing costs could increase accordingly. In addition, as is true with other MLPs (the common units of which are often viewed by investors as yield-oriented securities), our unit price is impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Our failure to maintain an adequate system of internal control over financial reporting could adversely affect our ability to accurately report our results.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide a reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. A material weakness is a deficiency, or a combination of deficiencies, in the internal control over financial reporting that results in a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are necessary for us to provide reliable financial reports and deter and detect any material fraud. If we cannot provide reliable financial reports or prevent material fraud, our reputation and operating results will be harmed. Our efforts to develop and maintain our internal control and to remediate material weaknesses in our controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other effective improvement of our internal controls, could harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

We face various security threats, including cybersecurity threats related to the security of our facilities and infrastructure or those of third parties, attempts to gain unauthorized access to sensitive information or to render data or systems unusable and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our facilities, infrastructure and information may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. For example, the gathering, processing, treating and transportation of natural gas from our gathering systems, processing facilities and pipelines are dependent on communications among our facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from our facilities. Disruption of those communications, whether caused by cybersecurity attacks or otherwise, may disrupt our ability to deliver natural gas and control these assets.
There is no assurance that we will not suffer material losses from cybersecurity attacks in the future, and as such threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity vulnerabilities. Any terrorist or cybersecurity

attack against, or other disruption of, our assets or computer systems could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flows rather than on our profitability. As a result, we may be prevented from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions for periods in which we record losses for financial accounting purposes and may not make cash distributions for periods in which we record net earnings for financial accounting purposes.
The amount of available cash required to pay the distribution announced for the quarter ended December 31, 2016, on all of our common units, general partner units, IDRs and Series A Preferred units was $182.1 million, or $728.4 million per year. The Class C unit distribution, if paid in cash, would have been $10.6 million for the quarter ended December 31, 2016.

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our systems. Therefore, in the future, throughput on our systems could be less than we anticipate.

We typically do not obtain independent evaluations of hydrocarbon reserves connected to our systems. Accordingly, we do not have independent estimates of total reserves connected to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our systems are less than we anticipate, or the timeline for the development of reserves is greater than we anticipate, and we are unable to secure additional sources of oil and natural gas, there could be a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our areas of operation. Our competitors may expand or construct midstream systems that would create additional competition for the services we provide to our customers. In addition, our customers, including Anadarko, may develop their own midstream systems in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our results of operations could be adversely affected by asset impairments.

If commodity prices decrease, we may be required to write down the value of our midstream properties if the estimated future cash flows from these properties fall below their net book value. Because we are an affiliate of Anadarko, the assets we acquire from Anadarko are recorded at Anadarko’s carrying value prior to the transaction. Accordingly, we may be at an increased risk for impairments because the initial book values of a substantial portion of our assets do not have a direct relationship with, and in some cases could be significantly higher than, the amounts we paid to acquire such assets. For example, see the discussion of material impairments at our Hilight system and Red Desert complex in Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Further, at December 31, 2016, we had $417.6 million of goodwill on our balance sheet. Goodwill is recorded when the purchase price of a business acquired exceeds the fair market value of the tangible and separately measurable intangible net assets. In addition, similar to the carrying value of the assets we acquired from Anadarko, part of our goodwill is an allocated portion of Anadarko’s goodwill, which we recorded as a component of the carrying value of the assets we acquired from Anadarko. As a result, we may be at increased risk for impairments relative to entities

who acquire their assets from third parties or construct their own assets, as the carrying value of our goodwill does not reflect, and in some cases is significantly higher than, the difference between the consideration we paid for our acquisitions and the fair value of the net assets on the acquisition date.

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Goodwill is not amortized, but instead must be tested at least annually for impairments, and more frequently when circumstances indicate likely impairments, by applying a fair-value-based test. Goodwill is deemed impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could lead to goodwill impairments, such as our inability to maintain throughput on our assets or sustained lower oil and natural gas prices, by reducing the fair value of the associated reporting unit. Prolonged low or further declines in commodity prices and changes to producers' drilling plans in response to lower prices could result in additional impairments in future periods. Future non-cash asset impairments could negatively affect our results of operations.

If third-party pipelines or other facilities interconnected to our gathering, transportation, treating or processing systems become partially or fully unavailable, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Our gathering, transportation, treating and processing systems are connected to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third-party pipelines or facilities is not within our control. If any of these pipelines or facilities becomes unable to transport, treat or process crude oil, natural gas or NGLs, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or facilities, our revenues and cash available for distribution could be adversely affected.

Our interstate natural gas and liquids transportation assets and operations are subject to regulation by FERC, which could have an adverse effect on our revenues and our ability to make distributions.

Our interstate natural gas pipelines are subject to regulation by FERC. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. FERC has civil penalty authority to impose penalties for certain violations of up to $1.0 million per day for each violation. FERC also has the power to order disgorgement of profits from transactions deemed to violate applicable statutes.

Our interstate liquids pipelines are common carriers and are also subject to regulation by FERC. FERC regulation requires that common carrier liquid pipeline rates and interstate natural gas pipeline rates be filed with FERC and that these rates be "just and reasonable" and not unduly discriminatory. Interested persons may challenge proposed new or changed rates, and FERC is authorized to suspend the effectiveness of such rates pending an investigation or hearing. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Accordingly, action by FERC could adversely affect our ability to establish reasonable rates that cover operating costs and allow for a reasonable return. An adverse determination in any future rate proceeding brought by or against us could have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution. For example, one such matter relates to FERC's policy regarding allowances for income taxes in determining a regulated entity's cost of service. FERC allows regulated companies to recover an allowance for income taxes in rates only to the extent the company or its owners, such as our unitholders, are subject to U.S. income tax. This policy affects whom we allow to own our units, and if we are not successful in limiting ownership of our units to persons or entities subject to U.S. income tax, our FERC-regulated rates and revenues for our FERC-regulated gas and liquids pipelines could be adversely affected.

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A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.

We believe that our gathering systems meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. FERC, however, has not made any determinations with respect to the jurisdictional status of any of these gathering systems. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of ongoing litigation and, over time, FERC policy concerning which activities it regulates and which activities are excluded from its regulation has changed. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has regulated the gathering activities of interstate pipeline transmission companies more lightly, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels. FERC makes jurisdictional determinations for both natural gas gathering and liquids lines on a case-by-case basis. The classification and regulation of our pipelines are subject to change based on future determinations by FERC, the courts or Congress. A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.

The adoption of climate change or other air emissions legislation or regulations restricting emissions of GHGs or other air pollutants could result in increased operating costs and reduced demand for the gathering, processing, compressing, treating and transporting services we provide.

Changes in, or reinterpretations of, these laws and regulations that govern areas where we operate may negatively impact our operations. Examples of recent proposed and final regulations or other regulatory initiatives are included below.

- Ground-Level Ozone Standards. In October 2015, the EPA issued a rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (“NAAQS”) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA is expected to make final geographical attainment designations and issue final non-attainment area requirements pursuant to this NAAQS rule by late 2017, and any designations or requirements that result in reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations, which could apply to our operations. Compliance with this rule could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

- Reduction of Methane Emissions by the Oil and Gas Industry. In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed oil and natural gas production and natural gas processing and transmission facilities. The EPA’s rule is comprised of New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified, or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued New Source Performance Standards published by the EPA in 2012, known as Subpart OOOO, by using certain equipment specific emissions control practices with respect to, among other things, hydraulically fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural gas processing plants and pneumatic pumps. Moreover, in November 2016, the EPA issued a final Information Collection Request seeking information about methane emissions from facilities and operators in the oil and natural gas industry. The EPA has indicated that it intended to use the information from this request to develop Existing Source Performance Standards for the oil and gas industry. Compliance with this rule could, among other things, require installation of new emission controls on some of our equipment and significantly increase our capital expenditures and operating costs.

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Reduction of Greenhouse Gas Emissions. The U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. Furthermore, the EPA has passed a rule, known as the Clean Power Plan, to limit GHGs from power plants, but on February 9, 2016, the U.S. Supreme Court stayed this rule while it is being challenged in the federal D.C. Circuit Court of Appeals. If this rule survives legal challenge, then depending on the methods used to implement this rule, it could reduce demand for the oil and natural gas our customers produce or increase the cost of electricity for our operations. In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Although this international agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. The adoption and implementation of any federal or state legislation or regulations that restrict emissions of GHGs or other air emissions could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows.

Derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, among other things, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us and Anadarko, that participate in that market. The Commodity Futures Trading Commission (the "CFTC") has finalized certain of its regulations under the Dodd-Frank Act, but others remain to be finalized or implemented. It is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be, so the impact of those rules is uncertain at this time.
The CFTC has designated certain types of swaps (thus far, only certain interest rate swaps and credit default swaps) for mandatory clearing and exchange trading, and may designate other types of swaps for mandatory clearing and exchange trading in the future. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. Although we are availing ourselves of the end-user exception to the mandatory clearing and exchange trading requirements for swaps designed to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we and Anadarko use for hedging. If any of our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions or execute them on a derivatives contract market or swap executive facility.
In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from margin requirements for swaps to other market participants, such as swap dealers, these rules may change the cost and availability of the swaps we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, we could be required to post initial or variation margin, which would impact liquidity and reduce our cash. This would in turn reduce our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity price contracts. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders. Further, to the extent our revenues are unhedged, they could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

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We may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to authority under federal law, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs for certain gas and hazardous liquid pipelines that, in the event of a pipeline leak or rupture, could affect HCAs, which are areas where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. These regulations require the operators of covered pipelines to: (i) perform ongoing assessments of pipeline integrity; (ii) identify and characterize applicable threats to pipeline segments that could impact HCAs; (iii) improve data collection, integration and analysis; (iv) repair and remediate the pipeline as necessary; and (v) implement preventive and mitigating actions. In addition, states have adopted regulations similar to existing PHMSA regulations for certain intrastate gas and hazardous liquid pipelines. At this time, we cannot predict the ultimate cost of compliance with these regulations, as the cost will vary significantly depending on the number and extent of any repairs or replacements of pipeline segments found to be necessary as a result of the pipeline integrity testing. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or replacements of pipeline segments deemed necessary to ensure the safe and reliable operation of our pipelines. Moreover, the adoption of any new legislation or regulations that impose more stringent or costly pipeline integrity management standards could result in a material adverse effect on our results of operations or financial position.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

In June 2016, PHMSA’s statutory mandate regarding pipeline safety was extended through 2019, and PHMSA was given expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment. The imposition of new safety requirements or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in us incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. For example, in January 2017, PHMSA issued a final rule that significantly extends and expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline’s proximity to a high consequence area. The final rule also imposes new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. However, the date of implementation of this final rule by publication in the Federal Register is uncertain given the recent change in presidential administrations. Additionally, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA’s current regulatory safety programs for natural gas pipelines in newly defined “moderate consequence areas” that contain as few as five dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their MAOP; and requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards. Additional requirements proposed by this proposed rulemaking would increase PHMSA’s integrity management requirements and also require consideration of seismicity in evaluating threats to pipelines. Additionally, PHMSA and one or more state regulators, including the RRC, have in recent years expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, to assess compliance with hazardous liquids pipeline safety requirements. To the extent that PHMSA and/or state regulatory agencies are successful in asserting their jurisdiction in this manner, midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current OSHA and EPA requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

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Some portions of our pipeline systems have been in service for several decades, and we have a limited ownership history with respect to certain of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and results of operations.

Some portions of the pipeline systems that we operate have been in service for many decades prior to our purchase. Consequently, there may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of our pipeline systems could adversely affect our business and results of operations.

We are subject to stringent and comprehensive environmental laws and regulations that may expose us to significant costs and liabilities.

Our operations are subject to stringent and comprehensive federal, tribal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relate to environmental protection. These environmental laws and regulations may impose numerous obligations that are applicable to our operations, including: (i) the acquisition of permits to conduct regulated activities; (ii) restrictions on the types, quantities and concentrations of materials that can be released into the environment; (iii) limitations on the generation, management and disposal of waste; (iv) limitation or prohibition on construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; (v) requiring capital expenditures to limit or prevent releases of materials from our pipelines and facilities; and (vi) imposition of substantial liabilities for pollution resulting from our operations or existing at our owned or operated facilities. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly remedial or corrective actions. Failure to comply with these laws, regulations and permits or any newly adopted legal requirements may result in the assessment of sanctions and administrative, civil and criminal penalties, the imposition of investigatory, remedial or corrective action obligations, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects, and the issuance of injunctions limiting or preventing some or all of our operations in particular areas.
We may incur significant environmental costs and liabilities in connection with our operations due to our handling of natural gas, NGLs and other petroleum products, because of air emissions and discharges related to our operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release as a result of our operations could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by owners of the properties through which our gathering or transportation systems pass, neighboring landowners, and other third parties for personal injury, natural resource and property damages, and fines or penalties for related violations of environmental laws or regulations. Joint and several strict liabilities may be incurred, without regard to fault, under certain of these environmental laws and regulations. In addition, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary, which could have a material adverse effect on our results of operations or financial condition. For example, regulatory initiatives targeting the reduction of certain air pollutants, such as ground level ozone or GHGs such as methane, or clarifying federal jurisdiction over waters of the United States that allegedly may broaden such jurisdiction in comparison to previous rulemakings have been proposed and/or adopted by the EPA but are currently subject to various legal impediments, including formalized opposition, lawsuits, and/or court stays. The adoption of these or any other laws, regulations or other legally enforceable mandates could increase our oil and natural gas customers' operating and compliance costs as well as reduce the rate of production of oil or natural gas from operators with whom we have a business relationship, which could have a material adverse effect on

our results of operations and cash flows.

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In addition, the legal requirements related to the disposal of wastewater in underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near injection wells used for the disposal of produced water resulting from oil and natural gas activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for wastewater disposal wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission adopted similar permitting, operating, and reporting rules for disposal wells in 2014. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on our use of injection wells, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through the construction of new midstream assets. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties that are beyond our control. These uncertainties could also affect downstream assets which we do not own or control, but which are critical to certain of our growth projects. Delays in the completion of new downstream assets, or the unavailability of existing downstream assets, due to environmental, regulatory or political considerations, could have an adverse impact on the completion or utilization of our growth projects. In addition, construction activities could be subject to state, county and local ordinances that restrict the time, place or manner in which those activities may be conducted. Construction projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenues until the project is completed. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we often do not have access to estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing assets may require us to obtain new rights-of-way. We may be unable to obtain such rights-of-way and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing existing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

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We have partial ownership interests in several joint venture legal entities which we do not operate or control. As a result, among other things, we may be unable to control the amount of cash we will receive or retain from the operation of these entities, and we could be required to contribute significant cash to fund our share of their operations, which could adversely affect our ability to distribute cash to our unitholders.

Our inability, or limited ability, to control the operations and/or management of joint venture legal entities in which we have a partial ownership interest may result in our receiving or retaining less than the amount of cash we expect. We also may be unable, or limited in our ability, to cause any such entity to effect significant transactions such as large expenditures or contractual commitments, the construction or acquisition of assets, or the borrowing of money. In addition, for the Fort Union, White Cliffs, Rendezvous and Mont Belvieu JV entities in which we have a minority ownership interest, we are unable to control ongoing operational decisions, including the incurrence of capital expenditures or additional indebtedness that we may be required to fund. Further, Fort Union, White Cliffs, Rendezvous or the Mont Belvieu JV may establish reserves for working capital, capital projects, environmental matters and legal proceedings, that would similarly reduce the amount of cash available for distribution. Any of the above could significantly and adversely impact our ability to make cash distributions to our unitholders.
Further, in connection with the acquisition of our membership interest in Chipeta, we became party to the Chipeta LLC agreement. Among other things, the Chipeta LLC agreement provides that to the extent available, Chipeta will distribute available cash, as defined in the Chipeta LLC agreement, to its members quarterly in accordance with those members' membership interests. Accordingly, we are required to distribute a portion of Chipeta's cash balances, which are included in the cash balances in our consolidated balance sheets, to the other Chipeta member.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial position and ability to make cash distributions to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, our operations and financial results could be adversely affected.

Our operations are subject to all of the risks and hazards inherent in gathering, processing, compressing, treating and transporting natural gas, crude oil and NGLs, including the following:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

- inadvertent damage from construction, farm and utility equipment;

- leaks or losses of hydrocarbons as a result of the malfunction of equipment or facilities;

- fires and explosions (for example, see Items Affecting Comparability of Our Financial Results, under Part II, Item 7 of this Form 10-K for a discussion of the incident at our DBM complex); and

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other hazards that could also result in personal injury, loss of life, pollution, natural resource damages and/or suspension of operations.

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These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental or natural resource damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to certain indemnification rights, for potential environmental liabilities.

We are exposed to the credit risk of third-party customers, and any material non-payment or non-performance by these parties, including with respect to our gathering, processing and transportation agreements, could reduce our ability to make distributions to our unitholders.

On some of our systems, we rely on third-party customers for substantially all of our revenues related to those assets. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, replacements of contracts or otherwise, could reduce our ability to make cash distributions to our unitholders. Further, to the extent any of our third-party customers is in financial distress or enters bankruptcy proceedings, the related customer contracts may be renegotiated at lower rates or rejected altogether.

The loss of, or difficulty in attracting and retaining, experienced personnel could reduce our competitiveness and prospects for future success.

The successful execution of our growth strategy and other activities integral to our operations depends, in part, on our ability to attract and retain experienced engineering, operating, commercial and other professionals. Competition for such professionals has historically been intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be adversely impacted.

We are required to deduct estimated future maintenance capital expenditures from operating surplus, which may result in less cash available for distribution to unitholders than if actual maintenance capital expenditures were deducted.

Our partnership agreement requires us to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus will be subject to review and change by the Special Committee of our Board of Directors at least once a year. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution will be lower than if actual maintenance capital expenditures were deducted from operating surplus. If we underestimate the appropriate level of estimated maintenance capital expenditures, we may have less cash available for distribution in future periods when actual capital expenditures begin to exceed our previous estimates. Over time, if we do not set aside sufficient cash reserves or have sufficient sources of financing available to make the expenditures required to maintain our asset base, we may be unable to pay distributions at the anticipated level and could be required to reduce our distributions.

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RISKS INHERENT IN AN INVESTMENT IN US

Anadarko, through its control of WGP, controls our general partner, which has sole responsibility for conducting our business and managing our operations. Anadarko, WGP and our general partner have conflicts of interest with, and may favor Anadarko's interests to the detriment of, our unitholders.

Anadarko, through its control of WGP, controls our general partner and indirectly has the power to appoint all of the officers and directors of our general partner. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner, WGP, in which Anadarko holds a controlling general partner interest and an 81.6% limited partner interest. Conflicts of interest may arise between Anadarko, WGP and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Anadarko and WGP over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Anadarko to pursue a business strategy that favors us.

- Anadarko is not limited in its ability to compete with us and may offer business opportunities or sell midstream assets to parties other than us.

- Our general partner is allowed to take into account the interests of parties other than us, such as Anadarko, in resolving conflicts of interest.

- The officers of our general partner will also devote significant time to the business of Anadarko and will be compensated by Anadarko accordingly. For example, all of the equity incentive compensation currently provided to the officers of our general partner is tied to Anadarko's common stock rather than our or WGP's common units.

- Our partnership agreement limits the liability of and reduces the default state law fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty under state law.

- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.

- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner.

- Our general partner determines which costs incurred by it are reimbursable by us.

- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make IDR payments.

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.

- Our general partner has limited, and intends to continue to limit, its liability regarding our contractual and other obligations.

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- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to the IDRs without the approval of the Special Committee of the Board of Directors or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Read Part III, Item 13 of this Form 10-K for additional information.

A reduction in Anadarko’s ownership interest in us may negatively impact its incentive to support the Partnership.

As discussed in Our Relationship with Anadarko Petroleum Corporation in Part I, Items 1 and 2 of this Form 10-K, we believe that one of our principal strengths is our relationship with Anadarko, and that Anadarko, through its significant indirect economic interest in us, will continue to be motivated to promote and support the successful execution of our business plan and to pursue projects that help to enhance the value of our business. In 2014, Anadarko began monetizing a portion of its investment in WGP, including the sale of an aggregate of 20,550,000 WGP common units and 9,200,000 tangible equity units, which partially consist of prepaid equity purchase contracts that can be settled in WGP common units. To the extent Anadarko’s net interest in us continues to diminish through the sale of its WGP holdings or otherwise, Anadarko may be less incentivized to grow our business by offering us assets or commercial arrangements. For example, a decrease in Anadarko’s net holdings in us could diminish its incentive to renew our commodity price swap agreements on terms as favorable as currently exist or at all. Accordingly, a decrease in Anadarko’s net holdings in us could have a material adverse effect on our business, results of operations, financial position and ability to grow or make cash distributions to our unitholders.

The duties of our general partner’s officers and directors may conflict with their duties as officers and directors of WGP’s general partner.

Our general partner’s officers and directors have duties to manage our business in a manner that is beneficial to us, our unitholders and the owner of our general partner, WGP, which is in turn controlled by Anadarko. However, 50% of our general partner’s directors and all of its officers are also officers and/or directors of WGP’s general partner, which has duties to manage the business of WGP in a manner beneficial to WGP and WGP’s unitholders, including Anadarko. Consequently, these directors and officers may encounter situations in which their obligations to us on the one hand, and WGP and/or Anadarko, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our unitholders.
In addition, our general partner’s officers, who are also the officers of WGP’s general partner and certain of whom are officers of Anadarko, will have responsibility for overseeing the allocation of their own time and time spent by administrative personnel on our behalf and on behalf of WGP and/or Anadarko. These officers may face conflicts regarding these time allocations.

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Neither Anadarko nor WGP is limited in its ability to compete with us or is obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could adversely affect our results of operations and cash available for distribution to our unitholders.

Neither Anadarko nor WGP is prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Anadarko or WGP may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to participate in such transactions. Moreover, while Anadarko may offer us the opportunity to buy additional assets from it, it is under no contractual obligation to do so and we are unable to predict whether or when such acquisitions might be completed.

Cost reimbursements due to Anadarko and our general partner for services provided to us or on our behalf are substantial and reduce our cash available for distribution to our unitholders. The amount and timing of such reimbursements are determined by our general partner.

Prior to making distributions on our common units, we reimburse Anadarko, which controls our general partner, and its affiliates for expenses they incur on our behalf as determined by our general partner pursuant to the omnibus agreement. These expenses include all costs incurred by Anadarko and our general partner in managing and operating us, as well as the reimbursement of incremental general and administrative expenses we incur as a result of being a publicly traded partnership. Our partnership agreement provides that Anadarko will determine in good faith the expenses that are allocable to us. Our general partner may, in good faith, significantly increase the amount of reimbursable general and administrative expenses in the future and any decision to do so would reduce the amount of cash otherwise available for distributions to our unitholders.

If you are not an Eligible Holder, you may not receive distributions or allocations of income or loss on your common units and your common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units. Eligible Holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity’s owners are U.S. individuals or entities subject to such taxation. If you are not an Eligible Holder, our general partner may elect not to make distributions or allocate income or loss on your units and you run the risk of having your units redeemed by us at the lower of your purchase price cost and the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

Our general partner’s liability regarding our obligations is limited.

Our general partner has included provisions in its and our contractual arrangements that limit its liability so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner’s duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

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Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will continue to distribute all of our available cash to our unitholders and will continue to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.
In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our partnership agreement, the indenture governing the Notes or our RCF on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

Our partnership agreement limits our general partner’s fiduciary duties to holders of our common units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include the following:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and
- whether to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

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- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith, meaning that it believed that the decision was in the best interest of the Partnership;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is any of the following:

(a) approved by the Special Committee of the Board of Directors, although our general partner is not obligated to seek such approval;
(b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;
(c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
(d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Special Committee and the Board of Directors determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the Partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner may elect to cause us to issue Class B and general partner units to it in connection with a resetting of the target distribution levels related to its IDRs, without the approval of the Special Committee of its Board of Directors or the holders of our common units. This could result in lower distributions to holders of our common units.

Our general partner has the right to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.
If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of Class B units and general partner units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued to our general partner will be equal to that number of common units which would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the IDRs in the prior two quarters. Our general partner will be issued the number of general partner units necessary to maintain its interest in us that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to

experience, declines in the cash distributions it receives related to its IDRs and may, therefore, desire to be issued Class B units, which are entitled to distributions on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new Class B units and general partner units to our general partner in connection with resetting the target distribution levels.

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Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our general partner or its Board of Directors. The Board of Directors is chosen by Anadarko (through its control of WGP). Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot remove our general partner without its consent.

Unitholders are currently unable to remove our general partner without its consent because our general partner and its affiliates currently own a sufficient percentage of the outstanding units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units (including general partner units, common units, Class C units and Series A Preferred units (on an as-converted basis)) voting together as a single class is required to remove our general partner. As of February 21, 2017, WGP owned a 29.9% limited partner interest in us. Other subsidiaries of Anadarko separately owned an aggregate 8.7% limited partner interest in us, consisting of common and Class C units. As such, Anadarko has the ability to prevent the removal of our general partner.

Our partnership agreement restricts the voting rights of certain unitholders owning 20% or more of our common units.

Unitholders' voting rights are restricted by a provision of our partnership agreement providing that any person or group that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, the initial purchasers of the Series A Preferred units, but only with respect to their Series A Preferred units or the common units into which they are converted, and persons who acquired such units with the prior approval of the Board of Directors, cannot vote on any matter.

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

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

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

The holders of our Series A Preferred units are entitled to certain rights that are senior to the rights of holders of common and Class C units, such as rights to distributions and rights upon liquidation of the Partnership. No payment or distribution on any junior equity security of the Partnership, including common and Class C units, for any quarter is permitted prior to the payment in full of the Series A Preferred unit distribution (including any outstanding arrearages). These preferences could adversely affect the market price for our common units, or could make it more difficult for us to issue and sell common units in the future. In addition, distributions on the Series A Preferred units accrue and are cumulative, at a quarterly rate of $0.68 per unit, and the Series A Preferred units are convertible into common units by the holders or by us in certain circumstances. Our obligation to pay distributions on the Series A Preferred units, or on the common units issued following the conversion of the Series A Preferred units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions and other general partnership purposes. Our obligations to the holders of Series A Preferred units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition. In addition, the holders of our Series A Preferred units may convert the Series A Preferred units into common units on a one-for-one basis at any time after the second anniversary of the issuance date, in whole or in part, subject to certain conversion thresholds. Similarly, the Partnership may convert the Series A Preferred units at any time after the third anniversary of the issuance date, in whole or in part, subject to certain conversion thresholds. If a substantial portion of the Series A Preferred units are converted into common units, common unitholders could experience significant dilution. Further, if holders of converted Series A Preferred units dispose of a substantial portion of such common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for our common units. These sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders’ proportionate ownership interest in us will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the ratio of taxable income to distributions may increase;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

WGP or affiliates may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of February 21, 2017, WGP held 50,132,046 common units and other subsidiaries of Anadarko held 2,011,380 common units and 12,537,100 Class C units. Additionally, the Class C units are entitled to receive distributions in the form of additional Class C units, which will increase the number of our common and Class C units owned by affiliates over time. The sale of any or all of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market on which common units are traded.

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Our general partner has a limited call right that may require existing unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price. As a result, existing unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Existing unitholders may also incur a tax liability upon a sale of their units. As of February 21, 2017, WGP owned a 29.9% limited partner interest in us, and other subsidiaries of Anadarko held an aggregate 8.7% limited partner interest in us, consisting of common and Class C units.

Unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for any and all of our obligations as if that unitholder were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or

- such unitholder's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

If we are deemed to be an "investment company" under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include, among other items, a $260.0 million note receivable from Anadarko. If this note receivable together with a sufficient amount of our other assets are deemed to be "investment securities," within the meaning of the Investment Company Act of 1940 (the "Investment Company Act"), we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or contract rights so as to fall outside of the definition of investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property from or to our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

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Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes, in which case we would be treated as a corporation for federal income tax purposes. As a result, we would pay federal, and possibly state, income taxes on our taxable income at the corporate tax rates, distributions to our unitholders would generally be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to our unitholders. If we were taxed as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as an investment company would result in a material reduction in the anticipated cash flows and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

The market price of our common units could be volatile due to a number of factors, many of which are beyond our control.

The market price of our common units could be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including the following:

- changes in investor or analyst estimates of Anadarko’s and our financial performance or our future distribution growth;
- the public’s reaction to Anadarko’s or our press releases, announcements and filings with the SEC;
- legislative or regulatory changes affecting our status as a partnership for federal income tax purposes;
- fluctuations in broader securities market prices and volumes, particularly among securities of midstream companies and securities of publicly traded limited partnerships;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of other midstream companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the midstream industry.

In recent years, the capital markets have experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to the operating performance of these companies. Future market fluctuations may result in a lower price of our common units.

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TAX RISKS TO COMMON UNITHOLDERS

Our taxation as a flow-through entity depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or if we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as us to be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement and is not treated as an investment company. Based on our current operations, we believe that we satisfy the qualifying income requirement, and we are not treated as an investment company. Failing to meet the qualifying income requirement, being treated as an investment company, a change in our business activities, or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.
If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.
Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income or franchise taxes, or other forms of taxation. For example, we are required to pay Texas margin tax on our gross income apportioned to Texas. Imposition of a similar tax on us in other jurisdictions to which we may expand our operations could substantially reduce the cash available for distribution to our unitholders.

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. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated 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.
Any modification 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 similar or future legislative changes could negatively impact the value of an investment in our common units.
In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the "Final Regulations") were published in the Federal Register. We do not

believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

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If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to the pricing of our related party agreements with Anadarko or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest with the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their respective interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Our unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, unitholders may be allocated taxable income and gain resulting from the sale, and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” being allocated to our unitholders as taxable income without any increase in our cash available for distribution. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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Tax gain or loss on the disposition of our common units could be more or less than expected.

If a unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease in that unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to that unitholder, if that unitholder sells such units at a price greater than that unitholder's tax basis in those units, even if the price received is less than their original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if they sell their units, unitholders may incur a tax liability in excess of the amount of cash they receive from the sale.
A substantial portion of the amount realized from a unitholder's sale of units, whether or not representing gain, may be taxed as ordinary income due to potential recapture of items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on the sale is less than the unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells units, the unitholder may recognize ordinary income from our allocations of income and gain prior to the sale and from recapture items, which generally cannot be offset by any capital loss recognized upon the sale of units.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (or "IRAs"), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file U.S. federal tax returns and pay tax on its share of our taxable income. Any tax-exempt entity or a non-U.S. person should consult its tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of common units and could negatively impact the value of our common units or result in audit adjustments to a unitholder's tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month (the "Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, which could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may, from time to time, consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.
A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could negatively impact the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. WGP directly and indirectly owns a significant portion of the total interest in our capital and profits. Therefore, a transfer by WGP of all or a portion of its interests in us (or a constructive termination of WGP) could, in conjunction with the trading of common units held by the public, result in a termination of our partnership for federal income tax purposes. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once.
Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in taxable income for the unitholder's taxable year that includes our termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for U.S. federal income tax purposes following the termination. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the

partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

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Our unitholders are subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders are subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, federal, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is the responsibility of each unitholder to file all U.S. federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

WGR Operating, LP, one of our subsidiaries, is currently in negotiations with the EPA with respect to alleged non-compliance with the leak detection and repair requirements of the federal Clean Air Act at its Granger, Wyoming facility. Although management cannot predict the outcome of settlement discussions, 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 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MARKET INFORMATION

Our common units are listed on the NYSE under the symbol "WES." The following table sets forth the high and low sales prices of the common units and the cash distribution per unit declared for the periods presented.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2016				
High Price	$60.44	$55.24	$53.45	$48.50
Low Price	52.52	46.85	39.73	25.40
Distribution per common unit	0.860	0.845	0.830	0.815
2015				
High Price	$54.35	$65.23	$74.30	$74.45
Low Price	36.70	43.88	62.21	62.71
Distribution per common unit	0.800	0.775	0.750	0.725

As of February 21, 2017, there were 23 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 2,583,068 general partner units, 12,537,100 Class C units and 21,922,831 Series A Preferred units; there is no established public trading market for any such units. All general partner units are held by our general partner, all Class C units are held by a subsidiary of Anadarko and all Series A Preferred units are held by private investors.

OTHER SECURITIES MATTERS

Unregistered sales of equity securities and use of proceeds. During the quarter ended December 31, 2016, the Partnership issued 197,699 PIK Class C units with an implied fair value of $11.1 million to AMH, the holder of the Class C units. 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 3—Partnership Distributions and Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Securities authorized for issuance under equity compensation plans. In connection with the closing of our IPO, our general partner adopted the WES LTIP, which permits the issuance of up to 2,250,000 units, of which 2,120,711 units remained available for future issuance as of December 31, 2016. Phantom unit grants under the WES LTIP have been made to each of the independent directors of our general partner and certain employees. Read the information under Part III, Item 12 of this Form 10-K, which is incorporated by reference into this Item 5.

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SELECTED INFORMATION FROM OUR PARTNERSHIP AGREEMENT

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions and the IDRs.

Available cash. Our partnership agreement requires us to distribute all of our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. The amount of available cash generally is all cash on hand at the end of the quarter, plus, at the discretion of our general partner, working capital borrowings made subsequent to the end of such quarter, less the amount of cash reserves established by our general partner to provide for the proper conduct of our business, including reserves to fund future capital expenditures; to comply with applicable laws, debt instruments or other agreements; or to provide funds for distributions to our unitholders, and to our general partner for any one or more of the next four quarters. Working capital borrowings generally include borrowings made under a credit facility or similar financing arrangement. Working capital borrowings may only be those that, at the time of such borrowings, were intended to be repaid within 12 months. In all cases, working capital borrowings are used solely for working capital purposes or to fund distributions to partners. Class C units are disregarded with respect to distributions of available cash until they are converted to common units.

General partner interest and incentive distribution rights. As of December 31, 2016, our general partner was entitled to 1.5% of all quarterly distributions that we make prior to our liquidation and, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented, after the minimum quarterly distribution and the target distribution levels had been achieved. The maximum distribution sharing percentage of 49.5% does not include any distributions that our general partner may receive on common units that it may acquire.

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Item 6. Selected Financial and Operating Data

The following Summary Financial Information table shows our selected financial and operating data, which are derived from our consolidated financial statements for the periods and as of the dates indicated.
The term “Partnership assets” refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2016 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). 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 II, Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control. For those periods requiring recast, the consolidated financial statements for periods prior to our acquisition of Partnership assets from Anadarko have been prepared from Anadarko’s historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the Partnership assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being “our” historical financial results.

Acquisitions. The following table presents the acquisitions completed by the Partnership since its inception through December 31, 2016. Our consolidated financial statements include the combined financial results and operations for: (i) affiliate acquisitions for all periods presented and (ii) third-party acquisitions since the acquisition date. See Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

	Acquisition Date	Percentage Acquired		Affiliate or Third-party Acquisition
Initial assets [(1)]	05/14/2008	100	%	Anadarko
Powder River assets [(2)]	12/19/2008	Various [(2)]		Anadarko
Chipeta	07/01/2009	51	%	Anadarko
Granger	01/29/2010	100	%	Anadarko
Wattenberg	08/02/2010	100	%	Anadarko
White Cliffs [(3)]	09/28/2010	10	%	Various [(3)]
Platte Valley	02/28/2011	100	%	Third party
Bison	07/08/2011	100	%	Anadarko
MGR	01/13/2012	100	%	Anadarko
Chipeta [(4)]	08/01/2012	24	%	Anadarko
Non-Operated Marcellus Interest	03/01/2013	33.75	%	Anadarko
Anadarko-Operated Marcellus Interest	03/08/2013	33.75	%	Third party
Mont Belvieu JV	06/05/2013	25	%	Third party
OTTCO	09/03/2013	100	%	Third party
TEFR Interests [(5)]	03/03/2014	Various [(5)]		Anadarko
DBM	11/25/2014	100	%	Third party
DBJV	03/02/2015	100	%	Anadarko
Springfield	03/14/2016	100	%	Anadarko

(1) Concurrently with the closing of our IPO, Anadarko contributed the initial assets to us.
(2) Acquired the Powder River assets, which included (i) the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% membership interest in Fort Union.
(3) Acquired a 10% interest in White Cliffs, which consisted of a 9.6% third-party interest and a 0.4% interest from Anadarko.

(4) Acquired Anadarko’s then-remaining 24% membership interest in Chipeta, receiving distributions related to the additional interest effective July 1, 2012.

(5) Acquired a 20% interest in each of TEG and TEP and a 33.33% interest in FRP.

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Divestitures. In October 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party. In July 2015, the Dew and Pinnacle systems in East Texas were sold to a third party. See Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

The information in the following table should be read together with the Consolidated Financial Statements and Notes to Consolidated Financial Statements, which are included under Part II, Item 8 of this Form 10-K, and with the information under the captions How We Evaluate Our Operations, Items Affecting the Comparability of Our Financial Results, Results of Operations, and Key Performance Metrics under Part II, Item 7 of this Form 10-K:

thousands except per-unit data, throughput, Adjusted gross margin per Mcf and Adjusted gross margin per Bbl	Summary Financial Information				
	2016	2015	2014	2013	2012
Statement of Operations Data (for the year ended):					
Total revenues	$1,804,270	$1,752,072	$1,533,377	$1,200,060	$998,031
Operating income (loss)	708,208	157,330	554,731	325,619	228,226
Net income (loss)	602,294	14,207	456,668	288,244	170,532
Net income attributable to noncontrolling interest	10,963	10,101	14,025	10,816	14,890
Net income (loss) attributable to Western Gas Partners, LP	591,331	4,106	442,643	277,428	155,642
Net income (loss) per common unit (basic)	1.74	(1.95)	2.13	1.83	0.84
Net income (loss) per common unit (diluted)	1.74	(1.95)	2.12	1.83	0.84
Distributions per unit	3.350	3.050	2.650	2.280	1.960
Balance Sheet Data (at year end):					
Total assets	$7,733,028	$7,301,197	$7,549,785	$5,328,224	$4,472,834
Total long-term liabilities	3,281,944	3,147,681	2,699,244	1,659,229	1,373,766
Total equity and partners’ capital	4,135,779	3,918,028	4,568,462	3,422,675	2,865,352
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$917,585	$785,645	$694,495	$601,335	$409,448
Investing activities	(1,105,534)	(500,277)	(2,740,175)	(1,858,912)	(1,633,408)
Financing activities	447,841	(254,389)	2,011,970	938,324	1,417,380
Capital expenditures	(473,858)	(637,503)	(804,822)	(851,771)	(913,834)
Throughput (MMcf/d except throughput measured in barrels):					
Total throughput for natural gas assets	4,064	4,300	3,984	3,611	3,211
Throughput attributable to noncontrolling interest for natural gas assets	124	142	165	168	228
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,940	4,158	3,819	3,443	2,983
Throughput for crude/NGL assets (MBbls/d)	184	186	154	62	44
Key Performance Metrics (for the year ended): (1)					
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$1,194,877	$1,119,555	$993,397	$775,040	$615,177
Adjusted gross margin for crude/NGL assets	142,566	131,492	103,102	31,664	20,776
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets	0.83	0.74	0.71	0.62	0.56
Adjusted gross margin per Bbl for crude/NGL assets	2.11	1.93	1.84	1.40	1.29
Adjusted EBITDA attributable to Western Gas Partners, LP	1,028,208	907,568	782,900	539,401	428,986
Distributable cash flow	852,446	781,383	661,133	455,238	355,559

(1) Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in GAAP. For definitions and reconciliations of Adjusted gross margin, Adjusted EBITDA and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, see the caption How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K.

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Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with the Consolidated Financial Statements and Notes to Consolidated Financial Statements, which are included under Part II, Item 8 of this Form 10-K, and the information set forth in Risk Factors under Part I, Item 1A of this Form 10-K.
The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K) by us as of December 31, 2016. 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 II, Item 8 of this Form 10-K). Further, after an acquisition of Partnership assets from Anadarko, we may be required to recast our financial statements to include the activities of such Partnership assets from the date of common control. For those periods requiring recast, the consolidated financial statements for periods prior to our acquisition of the Partnership assets from Anadarko have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if we had owned the Partnership assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being "our" historical financial results.

EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to acquire, own, develop and operate midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), North-central Pennsylvania and Texas. We are engaged in the business of gathering, compressing, treating, processing and transporting of natural gas, and gathering, stabilizing and transporting condensate, NGLs and crude oil. We are also currently constructing two produced-water disposal systems in West Texas, which are expected to be placed in service during the second quarter of 2017. We provide these midstream services for Anadarko, as well as for third-party producers and customers. As of December 31, 2016, our assets and investments consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Gathering systems	11	4	5	2
Treating facilities	12	12	—	3
Natural gas processing plants/trains	20	5	—	2
NGL pipelines	2	—	—	3
Natural gas pipelines	5	—	—	—
Oil pipelines	—	1	—	1

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Significant financial and operational events during the year ended December 31, 2016, included the following:

- We completed the acquisition of Springfield from Anadarko for cash and common unit consideration totaling $750.0 million. See Acquisitions and Divestitures under Part I, Items 1 and 2 of this Form 10-K for additional information.

- We issued 21,922,831 Series A Preferred units to private investors, generating net proceeds of $686.9 million, a portion of which was used to fund the acquisition of Springfield. See Equity Offerings under Part I, Items 1 and 2 of this Form 10-K for additional information.

- We completed the offering of $500.0 million aggregate principal amount of 2026 Notes in July 2016 and an offering of an additional $200.0 million in aggregate principal amount of 2044 Notes in October 2016. Net proceeds were used to repay amounts then outstanding under our RCF and for general partnership purposes, including capital expenditures. See Liquidity and Capital Resources within this Item 7 for additional information.

- We commenced operation of Trains IV and V at the DBM complex in May 2016 and October 2016, respectively. Both are 200 MMcf/d processing plants. Further, after sustaining damage during the December 3, 2015, incident at the DBM complex, Train II (with capacity of 100 MMcf/d) returned to service in December 2016 and Train III (with capacity of 200 MMcf/d) returned to service in May 2016.

- We received $33.8 million in cash proceeds from insurers related to the incident at the DBM complex, including $16.3 million for business interruption insurance claims and $17.5 million for property insurance claims. See Items Affecting the Comparability of Our Financial Results within this Item 7 for additional information.

- We raised our distribution to $0.860 per unit for the fourth quarter of 2016, representing a 2% increase over the distribution for the third quarter of 2016 and an 8% increase over the distribution for the fourth quarter of 2015.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,940 MMcf/d for the year ended December 31, 2016, representing a 5% decrease compared to the year ended December 31, 2015.

- Throughput for crude/NGL assets totaled 184 MBbls/d for the year ended December 31, 2016, representing a 1% decrease compared to the year ended December 31, 2015.

- Operating income (loss) was $708.2 million for the year ended December 31, 2016, representing a 350% increase compared to the year ended December 31, 2015.

- Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $0.83 per Mcf for the year ended December 31, 2016, representing a 12% increase compared to the year ended December 31, 2015.

- Adjusted gross margin for crude/NGL assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $2.11 per Bbl for the year ended December 31, 2016, representing a 9% increase compared to the year ended December 31, 2015.

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OUR OPERATIONS

Our results are driven primarily by the volumes of natural gas, NGLs and crude oil we service through our systems. For the year ended December 31, 2016, 68% of our total revenues and 47% of our throughput (excluding equity investment throughput) were attributable to transactions with Anadarko. We also recognized capital contributions from Anadarko of $45.8 million related to the above-market component of our commodity price swap agreements with Anadarko (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). We receive significant dedications from our largest customer, Anadarko. With respect to our Wattenberg, Haley, Helper and Clawson gathering systems, Anadarko has made dedications to us that will continue to expand as long as additional wells are connected to these gathering systems.

In our operations, we contract with producers and customers to provide midstream services focused on natural gas, NGLs and crude oil. We gather natural gas from individual wells located near our gathering systems and connect wells to gathering lines through which natural gas may be compressed and delivered to a processing plant, treating facility or downstream pipeline, and ultimately to end users. We treat a significant portion of the natural gas that we gather so that it will satisfy required specifications for pipeline transportation. We also gather crude oil from individual wells located near our gathering systems, and in some cases, treat or stabilize the crude oil to satisfy required specifications for pipeline transportation.

For the year ended December 31, 2016, 94% of our Adjusted gross margin was attributable to fee-based contracts, under which a fixed fee is received based on the volume or thermal content of the natural gas and on the volume of NGLs and oil we gather, process, treat or transport. This type of contract provides us with a relatively stable revenue stream that is not subject to direct commodity price risk, except to the extent that (i) we retain and sell drip condensate that is recovered during the gathering of natural gas from the wellhead or (ii) actual recoveries differ from contractual recoveries under a limited number of processing agreements.

For the year ended December 31, 2016, 6% of our Adjusted gross margin was attributable to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure. See How We Evaluate Our Operations under Part II, Item 7 of this Form 10-K. A majority of the commodity price risk associated with our percent-of-proceeds and keep-whole contracts is hedged under commodity price swap agreements with Anadarko, with such agreements set to expire on December 31, 2017. For the year ended December 31, 2016, 99% of our Adjusted gross margin was derived from either long-term, fee-based contracts or from percent-of-proceeds or keep-whole agreements that were hedged with commodity price swap agreements. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

We also have indirect exposure to commodity price risk in that the relatively volatile commodity price environment has caused and may continue to cause our current or potential customers to delay drilling or shut in production in certain areas, which would reduce the volumes of hydrocarbons available for our systems. We also bear a limited degree of commodity price risk through settlement of imbalances. Read Item 7A. Quantitative and Qualitative Disclosures About Market Risk under Part II of this Form 10-K.

As a result of our acquisitions from Anadarko and third parties, our results of operations, financial position and cash flows may vary significantly for 2016, 2015 and 2014 as compared to future periods. See the caption Items Affecting the Comparability of Our Financial Results, set forth below in this Item 7.

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HOW WE EVALUATE OUR OPERATIONS

Our management relies on certain financial and operational metrics to analyze our performance. These metrics are significant factors in assessing our operating results and profitability and include (1) throughput, (2) operating and maintenance expenses, (3) general and administrative expenses, (4) Adjusted gross margin (as defined below), (5) Adjusted EBITDA (as defined below) and (6) Distributable cash flow (as defined below).

Throughput. Throughput is an essential operating variable we use in assessing our ability to generate revenues. In order to maintain or increase throughput on our gathering and processing systems, we must connect additional wells to our systems. Our success in maintaining or increasing throughput is impacted by the successful drilling of new wells by producers that are dedicated to our systems, recompletions of existing wells connected to our systems, our ability to secure volumes from new wells drilled on non-dedicated acreage and our ability to attract natural gas, NGL or crude oil volumes currently serviced by our competitors. During the year ended December 31, 2016, we added 226 receipt points to our systems.

Operating and maintenance expenses. We monitor operating and maintenance expenses to assess the impact of such costs on the profitability of our assets and to evaluate the overall efficiency of our operations. Operating and maintenance expenses include, among other things, field labor, insurance, repair and maintenance, equipment rentals, contract services, utility costs and services provided to us or on our behalf. For periods commencing on the date of and subsequent to our acquisition of the Partnership assets, certain of these expenses are incurred under and governed by our services and secondment agreement with Anadarko.

General and administrative expenses. To help ensure the appropriateness of our general and administrative expenses and maximize our cash available for distribution, we monitor such expenses through comparison to prior periods, to the annual budget approved by our Board of Directors, as well as to general and administrative expenses incurred by similar midstream companies. Pursuant to the omnibus agreement, Anadarko and the general partner perform centralized corporate functions for us. General and administrative expenses for periods prior to our acquisition of the Partnership assets include costs allocated by Anadarko in the form of a management services fee, which approximated the general and administrative costs incurred by Anadarko attributable to the Partnership assets. For periods subsequent to our acquisition of the Partnership assets, Anadarko is no longer compensated for corporate services through a management services fee. Instead, allocations and reimbursements of general and administrative expenses are determined by Anadarko in its reasonable discretion, in accordance with our partnership and omnibus agreements. Amounts required to be reimbursed to Anadarko under the omnibus agreement also include those expenses attributable to our status as a publicly traded partnership, such as the following:

- expenses associated with annual and quarterly reporting;
- tax return and Schedule K-1 preparation and distribution expenses;
- expenses associated with listing on the NYSE; and
- independent auditor fees, legal expenses, investor relations expenses, director fees, and registrar and transfer agent fees.

See further detail in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Non-GAAP financial measures

Adjusted gross margin attributable to Western Gas Partners, LP. We define Adjusted gross margin attributable to Western Gas Partners, LP ("Adjusted gross margin") as total revenues and other, less cost of product and reimbursements for electricity-related expenses recorded as revenue, plus distributions from equity investments and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. We believe Adjusted gross margin is an important performance measure of the core profitability of our operations, as well as our operating performance as compared to that of other companies in our industry. Cost of product expenses include (i) costs associated with the purchase of natural gas and NGLs pursuant to our percent-of-proceeds and keep-whole processing contracts, (ii) costs associated with the valuation of our gas imbalances, and (iii) costs associated with our obligations under certain contracts to redeliver a volume of natural gas to shippers, which is thermally equivalent to condensate retained by us and sold to third parties. These expenses are subject to variability, although a majority of our exposure to commodity price risk inherent in our percent-of-proceeds and keep-whole contracts is mitigated through our commodity price swap agreements with Anadarko. For a discussion of commodity price swap agreements, see Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
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. See Key Performance Metrics within this Item 7.

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

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis;

- the ability of our assets to generate cash flow to make distributions; and

- the viability of acquisitions and capital expenditure projects and the returns on investment of various investment opportunities.

Distributable cash flow. We define "Distributable cash flow" as Adjusted EBITDA, plus interest income and the net settlement amounts from the sale and/or purchase of natural gas, condensate and NGLs under our commodity price swap agreements to the extent such amounts are not recognized as Adjusted EBITDA, less net cash paid (or to be paid) for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, Series A Preferred unit distributions and income taxes. We compare Distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the Coverage ratio of distributable cash flow to planned cash distributions. We believe Distributable cash flow is useful to investors because this measurement is used by many companies, analysts and others in the industry as a performance measurement tool to evaluate our operating and financial performance and compare it with the performance of other publicly traded partnerships.

While Distributable cash flow is a measure we use to assess our ability to make distributions to our unitholders, it should not be viewed as indicative of the actual amount of cash that we have available for distributions or that we plan to distribute for a given period. Furthermore, to the extent Distributable cash flow includes realized amounts recorded as capital contributions from Anadarko attributable to activity under our commodity price swap agreements, it is not a reflection of our ability to generate cash from operations.

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

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

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

	Year Ended December 31,		
thousands	2016	2015	2014
Reconciliation of Operating income (loss) to Adjusted gross margin attributable to Western Gas Partners, LP			
Operating income (loss)	$708,208	$157,330	$554,731
Add:			
Distributions from equity investments	103,423	98,298	81,022
Operation and maintenance	308,010	331,972	293,710
General and administrative	45,591	41,319	38,561
Property and other taxes	40,145	33,288	28,889
Depreciation and amortization	272,933	272,611	211,809
Impairments	15,535	515,458	5,125
Less:			
Gain (loss) on divestiture and other, net	(14,641)	57,024	(9)
Proceeds from business interruption insurance claims	16,270	—	—
Equity income, net – affiliates	78,717	71,251	57,836
Reimbursed electricity-related charges recorded as revenues	59,733	54,175	39,338
Adjusted gross margin attributable to noncontrolling interest	16,323	16,779	20,183
Adjusted gross margin attributable to Western Gas Partners, LP	$1,337,443	$1,251,047	$1,096,499
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$1,194,877	$1,119,555	$993,397
Adjusted gross margin for crude/NGL assets	142,566	131,492	103,102

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thousands	Year Ended December 31, 2016	2015	2014
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Adjusted EBITDA attributable to Western Gas Partners, LP			
Net income (loss) attributable to Western Gas Partners, LP	$591,331	$4,106	$442,643
Add:			
Distributions from equity investments	103,423	98,298	81,022
Non-cash equity-based compensation expense	5,591	4,402	4,095
Interest expense	114,921	113,872	76,766
Income tax expense	8,372	45,532	39,061
Depreciation and amortization [1]	270,311	270,004	209,240
Impairments	15,535	515,458	5,125
Other expense [1]	224	1,290	—
Less:			
Gain (loss) on divestiture and other, net	(14,641)	57,024	(9)
Equity income, net – affiliates	78,717	71,251	57,836
Interest income – affiliates	16,900	16,900	16,900
Other income [1] [2]	524	219	325
Adjusted EBITDA attributable to Western Gas Partners, LP	$1,028,208	$907,568	$782,900
Reconciliation of Net cash provided by operating activities to Adjusted EBITDA attributable to Western Gas Partners, LP			
Net cash provided by operating activities	$917,585	$785,645	$694,495
Interest (income) expense, net	98,021	96,972	59,866
Uncontributed cash-based compensation awards	856	214	175
Accretion and amortization of long-term obligations, net	3,789	(17,698)	(2,736)
Current income tax (benefit) expense	5,817	34,186	379
Other (income) expense, net [2]	(479)	619	(336)
Distributions from equity investments in excess of cumulative earnings – affiliates	21,238	16,244	18,055
Changes in operating working capital:			
Accounts receivable, net	48,947	4,371	(1,399)
Accounts and imbalance payables and accrued liabilities, net	(58,359)	(1,006)	34,980
Other	4,367	720	(3,996)
Adjusted EBITDA attributable to noncontrolling interest	(13,574)	(12,699)	(16,583)
Adjusted EBITDA attributable to Western Gas Partners, LP	$1,028,208	$907,568	$782,900
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$917,585	$785,645	$694,495
Net cash used in investing activities	(1,105,534)	(500,277)	(2,740,175)
Net cash provided by (used in) financing activities	447,841	(254,389)	2,011,970

(1) Includes our 75% share of depreciation and amortization; other expense; and other income attributable to the Chipeta complex. Other expense also includes $0.2 million and $0.4 million of lower of cost or market inventory adjustments at our DBM complex for the years ended December 31, 2016 and 2015, respectively.

(2) Excludes income of $0.5 million for the year ended December 31, 2014, related to a component of a gas processing agreement accounted for as a capital lease.

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thousands except Coverage ratio	Year Ended December 31, 2016	2015	2014
Reconciliation of Net income (loss) attributable to Western Gas Partners, LP to Distributable cash flow and calculation of the Coverage ratio			
Net income (loss) attributable to Western Gas Partners, LP	$591,331	$4,106	$442,643
Add:			
Distributions from equity investments	103,423	98,298	81,022
Non-cash equity-based compensation expense	5,591	4,402	4,095
Non-cash settled - interest expense, net [1]	(7,747)	14,400	—
Income tax (benefit) expense	8,372	45,532	39,061
Depreciation and amortization [2]	270,311	270,004	209,240
Impairments	15,535	515,458	5,125
Above-market component of swap extensions with Anadarko [3]	45,820	18,449	—
Other expense [2]	224	1,290	—
Less:			
Gain (loss) on divestiture and other, net	(14,641)	57,024	(9)
Equity income, net – affiliates	78,717	71,251	57,836
Cash paid for maintenance capital expenditures [2]	63,630	53,882	52,159
Capitalized interest	5,562	8,318	9,832
Cash paid for (reimbursement of) income taxes	838	(138)	(90)
Series A Preferred unit distributions	45,784	—	—
Other income [2] [4]	524	219	325
Distributable cash flow	$852,446	$781,383	$661,133
Distributions declared [5]			
Limited partners – common units	$437,747		
General partner	221,384		
Total	$659,131		
Coverage ratio	1.29 x		

(1) Includes amounts related to the Deferred purchase price obligation - Anadarko. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(2) Includes our 75% share of depreciation and amortization; other expense; cash paid for maintenance capital expenditures; and other income attributable to the Chipeta complex. Other expense also includes $0.2 million and $0.4 million of lower of cost or market inventory adjustments at our DBM complex for the years ended December 31, 2016 and 2015, respectively.

(3) See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(4) Excludes income of $0.5 million for the year ended December 31, 2014, related to a component of a gas processing agreement accounted for as a capital lease.

(5) Reflects cash distributions of $3.350 per unit declared for the year ended December 31, 2016.

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ITEMS AFFECTING THE COMPARABILITY OF OUR FINANCIAL RESULTS

Our historical results of operations and cash flows for the periods presented may not be comparable to future or historic results of operations or cash flows for the reasons described below. Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods.

Gathering and processing agreements. Certain of the gathering agreements for our initial assets, the Non-Operated Marcellus Interest systems, the DBJV system and the Springfield system allow for rate resets that target an agreed-upon rate of return over the life of the agreement. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Commodity price swap agreements. We have commodity price swap agreements with Anadarko to mitigate exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts. On December 1, 2016, we renewed our commodity price swap agreements with Anadarko for the DJ Basin complex and the MGR assets through December 31, 2017, with an effective date of January 1, 2017. Revenues or costs attributable to volumes settled during the respective extension period, at the applicable market price, will be recognized in the consolidated statements of operations. We will also record a capital contribution from Anadarko in our consolidated statement of equity and partners' capital for the amount by which the swap price exceeds the applicable market price. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for further information.

Income taxes. Income we have earned on and subsequent to the date of the acquisition of the Partnership assets is subject only to Texas margin tax because we are a non-taxable entity for U.S. federal income tax purposes. With respect to assets acquired from Anadarko, we record Anadarko's historic current and deferred income taxes for the periods prior to our ownership of the assets. For periods subsequent to our acquisitions from Anadarko, we are not subject to tax except for the Texas margin tax and, accordingly, do not record current and deferred federal income taxes related to such assets.

Acquisitions and divestitures. See Note 2—Acquisitions and Divestitures and Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for additional information.

- DBM acquisition. In November 2014, we acquired Nuevo from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC. We financed the acquisition with the issuance of $750.0 million of Class C units to a subsidiary of Anadarko, borrowings under our RCF and cash on hand, including the proceeds from the November 2014 equity offering. These assets have been recorded in our consolidated financial statements at their estimated fair values on the acquisition date under the acquisition method of accounting. Results of operations attributable to the DBM acquisition were included in our consolidated statement of operations beginning on the acquisition date in the fourth quarter of 2014.

- DBJV acquisition. In March 2015, we acquired Anadarko's interest in DBJV. We will make a cash payment on March 31, 2020, to Anadarko as consideration for the acquisition of DBJV. As of the acquisition date, we estimated the future payment to be $282.8 million, the net present value of which was $174.3 million. As of December 31, 2016, the net present value of this obligation was $41.4 million and has been recorded on the consolidated balance sheet under Deferred purchase price obligation - Anadarko. Accretion revision was $7.7 million for the year ended December 31, 2016, and accretion expense was $14.4 million and zero for the years ended December 31, 2015 and 2014, respectively.

- Dew and Pinnacle divestiture. In July 2015, the Dew and Pinnacle systems in East Texas were sold to a third party, resulting in a net gain on sale of $77.3 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

Hugoton divestiture. In October 2016, the Hugoton system, located in Southwest Kansas and Oklahoma, was sold to a third party, resulting in a net loss on sale of $12.0 million recorded as Gain (loss) on divestiture and other, net in the consolidated statements of operations.

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DBM complex. On December 3, 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. The majority of the damage was to the liquid handling facilities and the amine treating units at the inlet of the complex. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains and returned to service in December 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. For the year ended December 31, 2015, $20.3 million of losses were recorded in Gain (loss) on divestiture and other, net in the consolidated statements of operations, related to this involuntary conversion event based on the difference between the net book value of the affected assets and the insurance claim receivable. As of December 31, 2016 and 2015, the consolidated balance sheets include receivables of $30.0 million and $49.0 million, respectively, for a property insurance claim related to the incident at the DBM complex. As of December 31, 2016, we had received $33.8 million in cash proceeds from insurers related to the incident at the DBM complex, including $16.3 million for business interruption insurance claims and $17.5 million for property insurance claims. For ease of reference throughout the remainder of this Management's Discussion and Analysis, the damage to the processing facility and resulting lack of processing capacity and associated financial statement impact will be referred to as the "DBM outage." See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Impairments. During 2015, we recognized impairments of $280.2 million at the Red Desert complex and $220.9 million at the Hilight system. Using the income approach and Level 3 fair value inputs, the Red Desert complex was impaired to its estimated salvage value of $6.3 million and the Hilight system was impaired to its estimated fair value of $28.8 million. These impairments were triggered by a reduction in estimated future cash flows caused by the low commodity price environment and resulting reduced producer drilling activity and related throughput.

GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends and uncertainties. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from expected results.

Impact of crude oil, natural gas and NGL prices. Crude oil, natural gas and NGL prices can fluctuate significantly, which affects our customers' activity levels, and thus our throughput, revenues, distributable cash flow and capital spending plans. For example, NYMEX West Texas Intermediate crude oil daily settlement prices recently ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Also, daily settlement prices for NYMEX Henry Hub natural gas recently ranged from a high of $6.15 per MMBtu in February 2014 to a low of $1.64 per MMBtu in March 2016. The duration and magnitude of the recent decline in commodity prices cannot be predicted. Furthermore, this relatively volatile commodity price environment has impacted drilling activity in several basins served by our assets. Several of our customers, including Anadarko, reduced activity levels in those areas, shifting capital toward opportunities that offer higher margins and superior economics. This trend resulted in fewer new well connections and, in some cases, temporary curtailments of production in those areas. To the extent opportunities are available, we will continue to connect new wells to our systems to mitigate the impact of natural production declines in order to maintain throughput on our systems. However, our success in connecting new wells to our systems is dependent on the activities of producers and shippers.
Many of our customers, including Anadarko, have a variety of investment opportunities and the financial strength and operational flexibility to move capital spending from areas focused on near-term production growth to longer-dated projects. We will continue to evaluate the crude oil, NGL and natural gas price environments and adjust capital spending plans as prices fluctuate while maintaining the appropriate liquidity and financial flexibility.

Liquidity and access to capital markets. We require periodic access to capital in order to fund acquisitions and expansion projects. Under the terms of our partnership agreement, we are required to distribute all of our available cash to our unitholders, which makes us dependent upon raising capital to fund growth projects. Historically, MLPs have accessed the debt and equity capital markets to raise money for new growth projects and acquisitions. Market turbulence has from time to time either raised the cost of capital markets financing or, in some cases, temporarily made such financing unavailable. If we are unable either to access the capital markets or find alternative sources of capital, our growth strategy may be more challenging to execute.

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Our sources of liquidity as of December 31, 2016, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, $1.195 billion in available borrowing capacity under our RCF, and issuances of additional equity or debt securities. As of December 31, 2016, our long-term debt was rated “BBB-” with a stable outlook by S&P, “BBB-” with a stable outlook by Fitch, and “Ba1” with a stable outlook by Moody’s. In February 2016, Moody’s downgraded Anadarko’s senior unsecured ratings from Baa2 to Ba1, with a negative outlook, and downgraded our senior unsecured ratings from Baa3 to Ba1, with a negative outlook, both of which are below investment grade. In September 2016, Moody’s changed the outlook for Anadarko and us from negative to stable. We cannot be assured that our credit rating will not be downgraded further. The Moody’s downgrade and any further downgrades in our credit ratings will adversely affect our ability to raise debt in the public debt markets, which could negatively impact our cost of capital and ability to effectively execute aspects of our strategy.

Changes in regulations. Our operations and the operations of our customers have been, and will continue to be, affected by political developments and an increasing number of complex federal, state, tribal, local and other laws and regulations such as production restrictions, permitting delays, limitations on hydraulic fracturing and environmental protection regulations. We and our customers must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. For example, regulation of hydraulic fracturing is currently primarily conducted at the state level through permitting and other compliance requirements. If proposed federal legislation is adopted, it could establish an additional level of regulation and permitting. Any changes in statutory regulations or delays in the issuance of required permits may impact both the throughput on and profitability of our systems.

Impact of inflation. Although inflation in the United States has been relatively low in recent years, the U.S. economy could experience a significant inflationary effect from, among other things, the governmental stimulus plans enacted since 2008. To the extent permitted by regulations and escalation provisions in certain of our existing agreements, we have the ability to recover a portion of increased costs in the form of higher fees.

Impact of interest rates. Interest rates remained at or near historic lows during 2016. In December 2016, the Federal Open Market Committee raised the target range for the federal funds rate from 1/4 to 1/2 percent to 1/2 to 3/4 percent, representing the second federal funds rate increase in a decade. This increase, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. Additionally, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and an associated implied distribution yield. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity, or increase the cost of issuing equity, to make acquisitions, reduce debt or for other purposes. However, we expect our cost of capital to remain competitive, as our competitors would face similar circumstances.

Acquisition opportunities. As of December 31, 2016, Anadarko’s total domestic midstream asset portfolio, excluding the assets we own, consisted of seven gathering systems, 2,955 miles of pipeline, 18 processing and/or treating facilities, three oil pipelines, one NGL pipeline and three produced-water disposal systems. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time. See Note 14—Subsequent Events in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
As of December 31, 2016, WGP held a 29.9% limited partner interest in us, and through its ownership of our general partner, WGP indirectly held a 1.5% general partner interest in us, and 100% of our IDRs. As of December 31, 2016, other subsidiaries of Anadarko separately held an aggregate 8.6% limited partner interest in us, consisting of common and Class C units. Given Anadarko’s significant interests in us, we believe Anadarko will continue to be motivated to promote and support the successful execution of our business plan and to pursue projects that help to enhance the value of our business. However, Anadarko continually evaluates acquisitions and divestitures and may elect to

acquire, construct or dispose of midstream assets in the future without offering us the opportunity to participate in such transactions. Should Anadarko choose to pursue additional midstream asset sales, it is under no contractual obligation to offer assets or business opportunities to us. For example, on December 21, 2016, Anadarko announced it had agreed to sell its operated and non-operated upstream assets and operated midstream assets (excluding our interests) in the Marcellus shale to a third party.

We may also pursue certain asset acquisitions from third parties to the extent such acquisitions complement our or Anadarko’s existing asset base or allow us to capture operational efficiencies from Anadarko’s or third-party production. However, if we do not make additional acquisitions from Anadarko or third parties on economically acceptable terms, our future growth will be limited, and the acquisitions we make could reduce, rather than increase, our cash flows generated from operations on a per-unit basis.

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Produced water gathering and disposal. In certain basins, hydrocarbon production can result in significant amounts of produced water. In these instances, the produced water must be separated from the hydrocarbon components and disposed of by re-injecting the produced water back into underground formations. We are currently developing the infrastructure necessary to gather and dispose of produced water in areas where volumes of this byproduct can be substantial, including the Delaware Basin.

RESULTS OF OPERATIONS

OPERATING RESULTS

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

	Year Ended December 31,		
thousands	2016	2015	2014
Total revenues and other [1]	$1,804,270	$1,752,072	$1,533,377
Equity income, net – affiliates	78,717	71,251	57,836
Total operating expenses [1]	1,176,408	1,723,017	1,036,473
Gain (loss) on divestiture and other, net	(14,641)	57,024	(9)
Proceeds from business interruption insurance claims [2]	16,270	—	—
Operating income (loss)	708,208	157,330	554,731
Interest income – affiliates	16,900	16,900	16,900
Interest expense	(114,921)	(113,872)	(76,766)
Other income (expense), net	479	(619)	864
Income (loss) before income taxes	610,666	59,739	495,729
Income tax (benefit) expense	8,372	45,532	39,061
Net income (loss)	602,294	14,207	456,668
Net income attributable to noncontrolling interest	10,963	10,101	14,025
Net income (loss) attributable to Western Gas Partners, LP	$591,331	$4,106	$442,643
Key performance metrics [3]			
Adjusted gross margin attributable to Western Gas Partners, LP	$1,337,443	$1,251,047	$1,096,499
Adjusted EBITDA attributable to Western Gas Partners, LP	1,028,208	907,568	782,900
Distributable cash flow	852,446	781,383	661,133

(1) Revenues and other include amounts earned from services provided to our affiliates, as well as from the sale of residue and NGLs to our affiliates. Operating expenses include amounts charged by our affiliates for services as well as reimbursement of amounts paid by affiliates to third parties on our behalf. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(2) See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

(3) Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow are defined under the caption Key Performance Metrics within this Item 7. For reconciliations of Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, see How We Evaluate Our Operations–Reconciliation to non-GAAP Measures within this Item 7.

For purposes of the following discussion, any increases or decreases “for the year ended December 31, 2016” refer to the comparison of the year ended December 31, 2016, to the year ended December 31, 2015, and any increases or decreases “for the year ended December 31, 2015” refer to the comparison of the year ended December 31, 2015, to the year ended December 31, 2014.

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Throughput

	Year Ended December 31,				
	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Throughput for natural gas assets (MMcf/d)					
Gathering, treating and transportation	1,537	1,791	(14)%	1,888	(5)%
Processing	2,350	2,331	1 %	1,925	21 %
Equity investment (1)	177	178	(1)%	171	4 %
Total throughput for natural gas assets	4,064	4,300	(5)%	3,984	8 %
Throughput attributable to noncontrolling interest for natural gas assets	124	142	(13)%	165	(14)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets	3,940	4,158	(5)%	3,819	9 %
Throughput for crude/NGL assets (MBbls/d)					
Gathering, treating and transportation	57	69	(17)%	64	8 %
Equity investment (2)	127	117	9 %	90	30 %
Total throughput for crude/NGL assets	184	186	(1)%	154	21 %

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

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

Natural gas assets

Gathering, treating and transportation throughput decreased by 254 MMcf/d for the year ended December 31, 2016, primarily due to decreased throughput at the Bison facility due to volumes being diverted to a third-party treater and the sale of the Dew and Pinnacle systems in July 2015.

Gathering, treating and transportation throughput decreased by 97 MMcf/d for the year ended December 31, 2015, primarily due to the sale of the Dew and Pinnacle systems in July 2015, production declines in the areas around the Anadarko-Operated Marcellus Interest systems, the Bison facility and the Non-Operated Marcellus Interest systems. These decreases were partially offset by higher volumes at the Springfield gas gathering system and at the DBJV system due to increased production.

Processing throughput increased by 19 MMcf/d for the year ended December 31, 2016, primarily due to increased production in the areas around the DJ Basin complex and the start-up of Train IV at the DBM complex in May 2016. These increases were partially offset by production declines around the Chipeta and Granger complexes, the MGR assets, and the Hilight system.

Processing throughput increased by 406 MMcf/d for the year ended December 31, 2015, primarily due to increased production in the area around the DJ Basin complex and the acquisition of DBM in November 2014, partially offset by decreased throughput at the Chipeta complex due to decreased drilling activity in the Uinta Basin.

Equity investment throughput increased by 7 MMcf/d for the year ended December 31, 2015, primarily due to increased throughput at the Rendezvous system, offset by lower throughput at the Fort Union system due to production declines in the area.

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Crude/NGL assets

Gathering, treating and transportation throughput decreased by 12 MBbls/d for the year ended December 31, 2016, primarily due to decreased throughput at the Springfield oil gathering system due to production declines in the area. Equity investment throughput increased by 10 MBbls/d for the year ended December 31, 2016, primarily due to an increase in volumes on FRP as a result of increased production in the DJ Basin area.
Gathering, treating and transportation throughput increased by 5 MBbls/d for the year ended December 31, 2015, primarily due to increased throughput at the Springfield oil gathering system. Equity investment throughput increased by 27 MBbls/d for the year ended December 31, 2015, due to an increase in volumes from FRP and TEP, and the third quarter 2014 in-service date of a White Cliffs pipeline expansion.

Gathering, Processing and Transportation Revenues

	Year Ended December 31,				
thousands except percentages	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Gathering, processing and transportation revenues	$1,227,849	$1,128,838	9 %	$894,034	26 %

Revenues from gathering, processing and transportation increased by $99.0 million for the year ended December 31, 2016, primarily due to increases of (i) $114.0 million at the DJ Basin complex resulting from increased throughput ($108.4 million) and a higher gathering fee ($5.6 million), as well as (ii) $19.8 million at the DBM complex due to increased throughput and a higher processing fee. These increases were partially offset by decreases of (i) $22.0 million at the Springfield system due to a decrease in throughput and (ii) $17.6 million due to the sale of the Dew and Pinnacle systems in July 2015.
Revenues from gathering, processing and transportation increased by $234.8 million for the year ended December 31, 2015, primarily due to increases of (i) $181.1 million at the DJ Basin complex resulting from increased throughput ($139.7 million), a higher gathering fee ($37.0 million), and the introduction of a condensate handling fee in the first quarter of 2015 ($4.4 million), (ii) $49.6 million due to the acquisition of DBM in November 2014, (iii) $41.8 million at the Springfield system due to increased throughput, and (iv) $10.0 million 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. These increases were partially offset by decreases of (i) $21.3 million at the Non-Operated Marcellus Interest systems due to a decrease in average gathering rate and throughput, (ii) $13.6 million due to the sale of the Dew and Pinnacle systems in July 2015, and (iii) $10.8 million at the Chipeta complex due to decreased throughput.

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Natural Gas and Natural Gas Liquids Sales

	Year Ended December 31,				
thousands except percentages and per-unit amounts	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Natural gas sales [(1)]	$230,366	$242,826	(5)%	$167,814	45 %
Natural gas liquids sales [(1)]	341,947	375,123	(9)%	458,091	(18)%
Total	$572,313	$617,949	(7)%	$625,905	(1)%
Average price per unit [(1)]:					
Natural gas (per Mcf)	$2.51	$3.28	(23)%	$4.16	(21)%
Natural gas liquids (per Bbl)	19.96	22.38	(11)%	43.58	(49)%

(1) Excludes amounts considered above market, with respect to our swap extensions at the DJ Basin complex and the Hugoton system beginning July 1, 2015, that are recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

For the years ended December 31, 2016 and 2015, average natural gas and NGL prices included the effects of commodity price swap agreements attributable to sales for the Hugoton system (until its divestiture in October 2016), the MGR assets and the DJ Basin complex. For the year ended December 31, 2014, average natural gas and NGL 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. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

The decline in natural gas sales of $12.5 million for the year ended December 31, 2016, was primarily due to decreases of (i) $9.9 million at the Hilight system due to a decrease in average price and volumes sold, (ii) $5.5 million at the DJ Basin complex due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015, partially offset by an increase in volumes sold and (iii) $3.8 million at the MGR assets due to a decrease in volumes sold. These decreases were partially offset by an increase of $8.7 million at the DBM complex due to an increase in volumes sold.

The growth in natural gas sales of $75.0 million for the year ended December 31, 2015, was primarily due to increases of (i) $76.4 million due to the acquisition of DBM in November 2014 and (ii) $25.6 million at the DJ Basin complex due to an increase in volumes sold. These increases were partially offset by decreases of $24.7 million at the Hilight system and Granger complex due to a decrease in average price as a result of the expiration of swap agreements in December 2014.

The decline in NGLs sales of $33.2 million for the year ended December 31, 2016, was primarily due to decreases of (i) $35.6 million at the MGR assets due to a decrease in volumes sold and (ii) $8.3 million and $4.8 million at the DJ Basin complex and Hugoton system, respectively, due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015 for the DJ Basin complex and October 1, 2015 for the Hugoton system. These decreases were partially offset by an increase of $17.5 million at the DBM complex due to an increase in average price and volumes sold.

The decline in NGLs sales of $83.0 million for the year ended December 31, 2015, was primarily due to decreases of (i) $113.1 million at the Granger complex and the Hilight system due to a decrease in average price as a result of the expiration of swap agreements in December 2014, (ii) $19.5 million at the Chipeta complex due to a decrease in average price, (iii) $16.1 million at the DJ Basin complex due to a decrease in volumes sold and the partial equity treatment of our above-market swap extensions beginning July 1, 2015 (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K), and (iv) $10.0 million at the MGR assets due to a decrease in volumes sold. These decreases were partially offset by an increase of $82.5 million due to the acquisition of DBM in November 2014.

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Equity Income, Net – Affiliates

	Year Ended December 31,				
thousands except percentages	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Equity income, net – affiliates	$78,717	$71,251	10 %	$57,836	23 %

For the year ended December 31, 2016, equity income, net – affiliates increased by $7.5 million, primarily due to our 14.81% share of an impairment loss determined by the managing partner of Fort Union in 2015, and increases in equity income from the TEFR Interests and the Mont Belvieu JV due to increased volumes.
For the year ended December 31, 2015, equity income, net – affiliates increased by $13.4 million, primarily due to a full year of equity income recognized from the TEFR Interests in 2015 and the third quarter 2014 in-service date of a White Cliffs pipeline expansion. These increases were partially offset by our 14.81% share of an impairment loss determined by the managing partner of Fort Union, and a decrease in equity income from the Mont Belvieu JV.

Cost of Product and Operation and Maintenance Expenses

	Year Ended December 31,				
thousands except percentages	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
NGL purchases (1)	$238,660	$251,222	(5)%	$232,889	8 %
Residue purchases (1)	231,722	253,619	(9)%	186,341	36 %
Other (1)	23,812	23,528	1 %	39,149	(40)%
Cost of product	494,194	528,369	(6)%	458,379	15 %
Operation and maintenance	308,010	331,972	(7)%	293,710	13 %
Total cost of product and operation and maintenance expenses	$802,204	$860,341	(7)%	$752,089	14 %

(1) Excludes amounts considered above market, with respect to our swap extensions at the DJ Basin complex and the Hugoton system beginning July 1, 2015, that are recorded as capital contributions in the consolidated statements of equity and partners' capital. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Cost of product expense for the years ended December 31, 2016 and 2015, included the effects of commodity price swap agreements attributable to purchases for the Hugoton system (until its divestiture in October 2016), the MGR assets and the DJ Basin complex. Cost of product expense for the year ended December 31, 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. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
NGL purchases decreased by $12.6 million for the year ended December 31, 2016, primarily due to decreases of (i) $23.7 million at the MGR assets due to a decrease in volume and average swap price and (ii) $3.2 million at the Chipeta complex and $2.7 million at the Hilight system due to decreases in volumes and average prices. These decreases were partially offset by an increase of $19.0 million at the DBM complex due to an increase in volume.
NGL purchases increased by $18.3 million for the year ended December 31, 2015, primarily due to an increase of $80.2 million due to the acquisition of the DBM complex in November 2014, partially offset by decreases of (i) $46.0 million at the Hilight system and Granger complex due to decreases in average prices as a result of the expiration of swap agreements in December 2014 and (ii) $14.8 million at the Chipeta complex due to a decrease in average price.
Residue purchases decreased by $21.9 million for the year ended December 31, 2016, primarily due to decreases of (i) $9.8 million at the DJ Basin complex due to the partial equity treatment of our above-market swap extensions beginning July 1, 2015, partially offset by an increase in volume, (ii) $8.9 million at the Hilight system due to a decrease in volume and average price and (iii) $4.0 million at the MGR assets due to a decrease in volume, partially offset by an increase in average swap price. These decreases were partially offset by an increase of $3.4 million at the

DBM complex due to an increase in volume.

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Residue purchases increased by $67.3 million for the year ended December 31, 2015, primarily due to increases of (i) $75.7 million due to the acquisition of DBM in November 2014 and (ii) $37.2 million at the DJ Basin complex due to an increase in volume. These increases were partially offset by decreases of (i) $40.0 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) $4.4 million at the Granger straddle plant due to a decrease in volume.

Other items increased by $0.3 million for the year ended December 31, 2016, primarily due to fees paid for rerouting volumes due to the DBM outage, partially offset by changes in imbalance positions, primarily at the DJ Basin and DBM complexes.

Other items decreased by $15.6 million for the year ended December 31, 2015, primarily due to changes in imbalance positions at the DJ Basin complex.

Operation and maintenance expense decreased by $24.0 million for the year ended December 31, 2016, primarily due to decreases of (i) $9.9 million in other operating costs primarily attributable to the DJ Basin and DBM complexes and the DBJV and Springfield systems, (ii) $7.7 million in chemicals and treating services primarily attributable to the DJ Basin and DBM complexes, and the sale of the Dew and Pinnacle systems in July 2015, (iii) $4.6 million in plant repairs primarily at the DJ Basin and Chipeta complexes and Hilight system, partially offset by an increase at the DBM complex, and (iv) $2.0 million in measurement and well-testing analysis expense primarily attributable to the DJ Basin complex and the sale of the Dew and Pinnacle systems in July 2015. These decreases were partially offset by an increase of $2.9 million in utilities expense primarily at the DJ Basin complex.

Operation and maintenance expense increased by $38.3 million for the year ended December 31, 2015, primarily due to an increase of $41.1 million due to the acquisition of DBM in November 2014, partially offset by a decrease of $6.9 million due to the divestiture of the Dew and Pinnacle systems in July 2015.

Other Operating Expenses

	Year Ended December 31,				
thousands except percentages	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
General and administrative	$45,591	$41,319	10 %	$38,561	7 %
Property and other taxes	40,145	33,288	21 %	28,889	15 %
Depreciation and amortization	272,933	272,611	— %	211,809	29 %
Impairments	15,535	515,458	(97)%	5,125	NM
Total other operating expenses	$374,204	$862,676	(57)%	$284,384	NM

NM-Not Meaningful

General and administrative expenses increased by $4.3 million for the year ended December 31, 2016, primarily due to increases in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement.

General and administrative expenses increased by $2.8 million for the year ended December 31, 2015, primarily due to increases of (i) $1.3 million in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement, (ii) $0.9 million in pre-acquisition management services fees for expenses incurred by Anadarko related to Springfield and (iii) $0.5 million in consulting and audit fees.

Property and other taxes increased by $6.9 million for the year ended December 31, 2016, primarily due to ad valorem tax increases of $7.2 million at the DJ Basin complex and $1.0 million at the DBM complex, partially offset by ad valorem tax decreases of $1.5 million at the Chipeta complex and $0.9 million due to the sale of the Hugoton system in October 2016.

Property and other taxes increased by $4.4 million for the year ended December 31, 2015, primarily due to ad valorem tax increases of $3.7 million at the DJ Basin complex and $2.5 million due to the acquisition of DBM in November 2014, partially offset by a decrease of $2.3 million due to the divestiture of the Dew and Pinnacle systems in July 2015.

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Depreciation and amortization increased by $0.3 million for the year ended December 31, 2016, primarily due to depreciation expense increases of $22.9 million related to capital projects at the DJ Basin, DBM and Granger complexes and the DBJV, Non-Operated Marcellus Interest, and Springfield systems. These increases were partially offset by decreases of (i) $12.1 million at the MGR assets and the Hilight system due to asset impairments recognized in the first and fourth quarters of 2015, respectively, (ii) $7.0 million due to the sale of the Dew and Pinnacle systems in July 2015 and (iii) $3.5 million due to the sale of the Hugoton system in October 2016.

Depreciation and amortization increased by $60.8 million for the year ended December 31, 2015, primarily due to depreciation expense increases of (i) $42.9 million due to the acquisition of DBM in November 2014, (ii) $20.8 million associated with the completion of multiple compression projects and the start-up of Lancaster Train I in April 2014 at the DJ Basin complex and (iii) $10.4 million at the Hilight, DBJV, Haley and Springfield systems. These increases were partially offset by decreases of (i) $7.1 million due to the divestiture of the Dew and Pinnacle systems in July 2015 and (ii) $9.8 million due to the impact of the impairment at the Red Desert complex during 2015.

Impairment expense decreased by $499.9 million for the year ended December 31, 2016, due to (i) impairments of $280.2 million at the Red Desert complex and $220.9 million at the Hilight system recognized during 2015 (discussed below) and (ii) impairments of $14.4 million primarily due to the abandonment of compressors at the MIGC system and the cancellation of projects at the Non-Operated Marcellus Interest systems and the Brasada, Red Desert and DJ Basin complexes during 2015. Impairment expense for the year ended December 31, 2016, included (i) the $6.1 million impairment at the Newcastle system, which was impaired to its estimated fair value of $3.1 million, using the income approach and Level 3 fair value inputs, due to a reduction in estimated future cash flows caused by the low commodity price environment and (ii) impairments of $9.4 million primarily related to the cancellation of projects at the DJ Basin complex and Springfield and DBJV systems, and the abandonment of compressors at the MIGC system in 2016.

Impairment expense increased by $510.3 million for the year ended December 31, 2015, due to impairments of $280.2 million at the Red Desert complex and $220.9 million at the Hilight system during 2015. Using the income approach and Level 3 fair value inputs, the Red Desert complex was impaired to its estimated salvage value of $6.3 million and the Hilight system was impaired to its estimated fair value of $28.8 million. These impairments were triggered by 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 2015, impairments of $14.4 million were recognized primarily due to (i) the abandonment of compressors at the MIGC system and (ii) the cancellation of projects at the Non-Operated Marcellus Interest systems and the Brasada, Red Desert and DJ Basin complexes. Impairment expense of $5.1 million for the year ended December 31, 2014, primarily related to (i) a non-operational plant in the Powder River Basin that was impaired to its estimated salvage value of $2.4 million, using the income approach and Level 3 fair value inputs, (ii) the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems and (iii) a compressor no longer in service at the Hilight system.

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Interest Income – Affiliates and Interest Expense

thousands except percentages	Year Ended December 31, 2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Note receivable – Anadarko	$16,900	$16,900	— %	$16,900	— %
Interest income – affiliates	$16,900	$16,900	— %	$16,900	— %
Third parties					
Long-term debt	$(121,832)	$(102,058)	19 %	$(81,495)	25 %
Amortization of debt issuance costs and commitment fees	(6,398)	(5,734)	12 %	(5,103)	12 %
Capitalized interest	5,562	8,318	(33)%	9,832	(15)%
Affiliates					
Deferred purchase price obligation – Anadarko[1]	7,747	(14,398)	(154)%	—	— %
Interest expense	$(114,921)	$(113,872)	1 %	$(76,766)	48 %

(1) See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of the Deferred purchase price obligation - Anadarko.

Interest expense increased by $1.0 million for the year ended December 31, 2016, primarily due to (i) $10.9 million of interest incurred on the 2026 Notes issued in July 2016, (ii) $8.4 million of interest incurred on the 2025 Notes issued in June 2015 and (iii) $2.2 million of interest incurred on the additional 2044 Notes issued in October 2016. These increases were partially offset by accretion revisions recorded as reductions to interest expense for the Deferred purchase price obligation - Anadarko entered into in March 2015 (see Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). Capitalized interest decreased by $2.8 million for the year ended December 31, 2016, primarily due to the completion of Lancaster Train II in June 2015 (within the DJ Basin complex), partially offset by an increase due to the construction of Trains IV, V and VI at the DBM complex. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Interest expense increased by $37.1 million for the year ended December 31, 2015, primarily due to (i) $14.4 million in accretion recorded to interest expense for the Deferred purchase price obligation - Anadarko, (ii) $11.4 million of interest incurred on the 2025 Notes issued in June 2015, (iii) $4.8 million of interest incurred on the 2044 Notes issued in March 2014, (iv) additional interest incurred on the RCF of $3.9 million as a result of higher average borrowings outstanding, and (v) $0.6 million of interest incurred on the additional 2018 Notes issued in March 2014. Capitalized interest decreased by $1.5 million for the year ended December 31, 2015, primarily due to the completion of Lancaster Train I in April 2014 and Lancaster Train II in June 2015 (both within the DJ Basin complex). This decrease was partially offset by an increase due to the construction of Trains IV and V at the DBM complex (acquired in November 2014). See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Income Tax (Benefit) Expense

thousands except percentages	Year Ended December 31, 2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Income (loss) before income taxes	$610,666	$59,739	NM	$495,729	(88)%
Income tax (benefit) expense	8,372	45,532	(82)%	39,061	17 %
Effective tax rate	1 %	76 %		8 %	

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, the 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 became effective January 1, 2016. We were 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 recorded in June 2015 and was included in the income tax (benefit) expense for the year ended December 31, 2015.

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

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KEY PERFORMANCE METRICS

	Year Ended December 31,				
thousands except percentages and per-unit amounts	2016	2015	Inc/ (Dec)	2014	Inc/ (Dec)
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets [(1)]	$1,194,877	$1,119,555	7 %	$993,397	13 %
Adjusted gross margin for crude/NGL assets [(2)]	142,566	131,492	8 %	103,102	28 %
Adjusted gross margin attributable to Western Gas Partners, LP [(3)]	1,337,443	1,251,047	7 %	1,096,499	14 %
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets [(4)]	0.83	0.74	12 %	0.71	4 %
Adjusted gross margin per Bbl for crude/NGL assets [(5)]	2.11	1.93	9 %	1.84	5 %
Adjusted EBITDA attributable to Western Gas Partners, LP [(3)]	1,028,208	907,568	13 %	782,900	16 %
Distributable cash flow [(3)]	852,446	781,383	9 %	661,133	18 %

(1) Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets is calculated as total revenues and other for natural gas assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for natural gas assets, plus distributions from our equity investments in Fort Union and Rendezvous, and excluding the noncontrolling interest owner's proportionate share of revenue and cost of product. See the reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets to its most comparable GAAP measure under How We Evaluate Our Operations—Reconciliation to GAAP measures within this Item 7.

(2) Adjusted gross margin for crude/NGL assets is calculated as total revenues and other for crude/NGL assets, less reimbursements for electricity-related expenses recorded as revenue and cost of product for crude/NGL assets, plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, and the TEFR Interests. See the reconciliation of Adjusted gross margin for crude/NGL assets to its most comparable GAAP measure under How We Evaluate Our Operations—Reconciliation to GAAP measures within this Item 7.

(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 How We Evaluate Our Operations—Reconciliation to GAAP measures within this Item 7.

(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. Adjusted gross margin increased by $86.4 million for the year ended December 31, 2016, primarily due to an increase in volumes at the DJ Basin and DBM complexes and the Haley system. These increases were partially offset by the sale of the Dew and Pinnacle systems in July 2015 and lower volumes at the MGR assets and the Springfield and Hugoton systems.

Adjusted gross margin increased by $154.5 million for the year ended December 31, 2015, primarily due to the start-up of Lancaster Train I in April 2014 and Lancaster Train II in June 2015 (both part of the DJ Basin complex), the acquisition of DBM in November 2014 and higher volumes at the Springfield gas gathering system. This increase was partially offset by margin decreases at the Granger complex due to lower average pricing, at the Non-Operated Marcellus Interest systems due to a decrease in the average gathering rate and at the Chipeta complex due to lower volumes, as well as the sale of the Dew and Pinnacle systems in July 2015.

Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.09 for the year ended December 31, 2016, primarily due to increased volumes in the DJ Basin due to the start-up of Lancaster Train II in June 2015 (within the DJ Basin complex) and increased volumes in West Texas due to the start-up of Trains IV and V (both within the DBM complex) in May 2016 and October 2016, respectively. These increases were partially offset by decreased volumes at the Springfield gas gathering system.

Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets increased by $0.03 for the year ended December 31, 2015, primarily due to the start-up of Lancaster Train I in April 2014 and Lancaster Train II in June 2015 (both within the DJ Basin complex), the acquisition of DBM in November 2014 and higher volumes at the Springfield gas gathering system.

Adjusted gross margin per Bbl for crude/NGL assets increased by $0.18 for the year ended December 31, 2016, primarily due to higher distributions received from the Mont Belvieu JV and White Cliffs.

Adjusted gross margin per Bbl for crude/NGL assets increased by $0.09 for the year ended December 31, 2015, primarily due to higher volumes at the Springfield oil gathering system.

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Adjusted EBITDA. Adjusted EBITDA increased by $120.6 million for the year ended December 31, 2016, primarily due to a $52.2 million increase in total revenues and other, a $33.9 million decrease in cost of product (net of lower of cost or market inventory adjustments), a $24.0 million decrease in operation and maintenance expenses, $16.3 million in business interruption proceeds, and a $5.1 million increase in distributions from equity investments. These amounts were partially offset by a $6.9 million increase in property and other tax expense, a $3.1 million increase in general and administrative expenses excluding non-cash equity-based compensation expense, and a $0.9 million increase in net income attributable to noncontrolling interest.

Adjusted EBITDA increased by $124.7 million for the year ended December 31, 2015, primarily due to a $218.7 million increase in total revenues and other, a $17.3 million increase in distributions from equity investments and a $3.9 million decrease in net income attributable to noncontrolling interest. These amounts were partially offset by a $69.5 million increase in cost of product (net of lower of cost or market inventory adjustments), a $38.3 million increase in operation and maintenance expenses, a $4.4 million increase in property and other tax expense, and a $2.5 million increase in general and administrative expenses excluding non-cash equity-based compensation expense.

Distributable cash flow. Distributable cash flow increased by $71.1 million for the year ended December 31, 2016, primarily due to a $120.6 million increase in Adjusted EBITDA and $27.4 million from the above-market component of the swap extensions with Anadarko, where such amount related to the above-market component of swaps did not exist prior to the extensions executed on July 1, 2015. These amounts were partially offset by distributions of $45.8 million on the Series A Preferred units issued in 2016, a $20.4 million increase in net cash paid for interest expense and a $9.7 million increase in cash paid for maintenance capital expenditures.

Distributable cash flow increased by $120.3 million for the year ended December 31, 2015, primarily due to a $124.7 million increase in Adjusted EBITDA and $18.4 million from the above-market component of the swap extensions with Anadarko, where such amount related to the above-market component of swaps did not exist prior to the extensions executed on July 1, 2015. These amounts were partially offset by a $21.2 million increase in net cash paid for interest expense and a $1.7 million increase in cash paid for maintenance capital expenditures.

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 December 31, 2016, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional equity or debt securities. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, capital requirements and other factors, including the extension of commodity price swap agreements, and will be determined by the Board of Directors on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including equity and debt issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under our RCF to pay distributions or fund other short-term working capital requirements.

We have filed an insurance claim for the incident at the DBM complex and are currently in the adjusting process with insurers. Recoveries from the business interruption claim related to the DBM outage are recognized as income when cash proceeds are received from insurers. As of December 31, 2016, we had received $33.8 million in cash proceeds from insurers related to the incident at the DBM complex, including $16.3 million for business interruption insurance claims and $17.5 million for property insurance claims (see Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). In January 2017, we received an additional $29.8 million in cash proceeds that will be recorded in the first quarter of 2017, including $5.8 million for business interruption insurance claims and $24.0 million for property insurance claims.

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Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our IPO and have increased our quarterly distribution each quarter since the second quarter of 2009. The Board of Directors declared a cash distribution to our unitholders for the fourth quarter of 2016 of $0.860 per unit, or $170.7 million in aggregate, including incentive distributions, but excluding distributions on Class C units and Series A Preferred units. The cash distribution was paid on February 13, 2017, to unitholders of record at the close of business on February 2, 2017. In connection with the closing of the DBM acquisition in November 2014, we issued Class C units that will receive distributions in the form of additional Class C units until the end of 2017, unless earlier converted (see Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K). The Class C unit distribution, if paid in cash, would have been $10.6 million for the fourth quarter of 2016. In connection with the closing of the Springfield acquisition in March 2016, we issued the March 2016 Series A units, and in April 2016, we issued the April 2016 Series A units pursuant to the full exercise of the option granted in connection with the March 2016 Series A units issuance. These Series A Preferred units will receive quarterly distributions in cash equal to $0.68 per Series A Preferred unit, subject to certain adjustments. See Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. For the quarter ended December 31, 2016, the Series A Preferred unitholders received an aggregate cash distribution of $14.9 million, paid in February 2017.
Management continuously monitors our leverage position and coordinates our capital expenditure program, quarterly distributions and acquisition strategy with our expected cash flows and projected debt-repayment schedule. We will continue to evaluate funding alternatives, including additional borrowings and the issuance of debt or equity securities, to secure funds as needed or to refinance outstanding debt balances with longer term notes. To facilitate a potential debt or equity securities issuance, we have the ability to sell securities under our shelf registration statements. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Read Risk Factors under Part I, Item 1A of this Form 10-K.

Working capital. As of December 31, 2016, we had $278.7 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital includes the estimated property insurance receivable related to the DBM outage. See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K. 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 December 31, 2016, we had $1.195 billion available for borrowing under our RCF. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures. Our business is capital intensive, requiring significant investment to maintain and improve existing facilities or develop new midstream infrastructure. We categorize capital expenditures as either of the following:

- maintenance capital expenditures, which include those expenditures required to maintain the existing operating capacity and service capability of our assets, such as to replace system components and equipment that have been subject to significant use over time, become obsolete or reached the end of their useful lives, to remain in compliance with regulatory or legal requirements or to complete additional well connections to maintain existing system throughput and related cash flows; or

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

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

	Year Ended December 31,		
thousands	2016	2015	2014
Acquisitions	$716,465	$14,417	$1,902,520
Expansion capital expenditures	$410,221	$583,282	$752,207
Maintenance capital expenditures	63,637	54,221	52,615
Total capital expenditures [1] [2]	$473,858	$637,503	$804,822
Capital incurred [2]	$491,349	$566,045	$833,872

(1) Capital expenditures for the years ended December 31, 2016, 2015 and 2014, are presented net of $6.1 million, $0.5 million and $0.2 million, respectively, of contributions in aid of construction costs from affiliates.

(2) Includes the noncontrolling interest owner’s share of Chipeta’s capital expenditures for all periods presented. For the years ended December 31, 2016, 2015 and 2014, included $5.6 million, $8.3 million and $9.8 million, respectively, of capitalized interest.

Acquisitions during 2016 included Springfield and equipment purchases from Anadarko. Acquisitions during 2015 included equipment purchases from Anadarko and the post-closing purchase price adjustments related to the DBM acquisition. Acquisitions during 2014 included DBM and the TEFR Interests. See Note 2—Acquisitions and Divestitures and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures, excluding acquisitions, decreased by $163.6 million for the year ended December 31, 2016. Expansion capital expenditures decreased by $173.1 million (including a $2.8 million decrease in capitalized interest) for the year ended December 31, 2016, primarily due to a decrease of $188.8 million at the DJ Basin complex as a result of decreased activity in 2016. In addition, there were decreases of $35.7 million at the Non-Operated Marcellus Interest systems, $30.0 million at the Springfield system, $18.4 million at the Hilight system, $13.5 million at the Haley system, and $9.3 million at the Anadarko-Operated Marcellus Interest systems. These decreases were partially offset by an increase of $102.8 million due to continued construction at the DBM complex and an increase of $24.5 million at the DBJV system. Maintenance capital expenditures increased by $9.4 million, primarily due to an increase at the DBM complex, partially offset by decreased expenditures at the DJ Basin complex and the Non-Operated Marcellus Interest and Springfield systems.

Capital expenditures, excluding acquisitions, decreased by $167.3 million for the year ended December 31, 2015. Expansion capital expenditures decreased by $168.9 million (including a $1.5 million decrease in capitalized interest) for the year ended December 31, 2015, primarily due to a decrease of $200.4 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 $47.9 million at the Springfield system, $39.9 million at the Hilight system, $14.2 million at the Non-Operated Marcellus Interest systems, $13.9 million at the Anadarko-Operated Marcellus Interest systems, $12.6 million at the Brasada complex and $11.1 million at the Red Desert complex. These decreases were partially offset by an increase of $163.5 million due to the acquisition of DBM in November 2014 and $12.1 million at the DBJV system.

We estimate our total capital expenditures for the year ending December 31, 2017, including our 75% share of Chipeta’s capital expenditures and excluding acquisitions, to be between $900 million and $1.0 billion and our maintenance capital expenditures to be between $60 million and $80 million. Expected 2017 projects are focused in West Texas and include continued expansion at the DBJV system, construction of Train VI at our DBM complex, two initial trains at the Mentone gas plant and two produced-water disposal systems. See Assets Under Development under Part I, Items 1 and 2 of this Form 10-K. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us, which are dependent, in part, on the drilling activities of Anadarko and third-party producers. We expect to fund future capital expenditures from cash flows generated from our operations, interest income from our note receivable from Anadarko, borrowings under our RCF, the issuance of additional partnership units or debt offerings.

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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:

	Year Ended December 31,		
thousands	2016	2015	2014
Net cash provided by (used in):			
Operating activities	$917,585	$785,645	$694,495
Investing activities	(1,105,534)	(500,277)	(2,740,175)
Financing activities	447,841	(254,389)	2,011,970
Net increase (decrease) in cash and cash equivalents	$259,892	$30,979	$(33,710)

Operating Activities. Net cash provided by operating activities during the years ended December 31, 2016, 2015 and 2014, increased primarily due to the impact of changes in working capital items. Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods.

Investing Activities. Net cash used in investing activities for the year ended December 31, 2016, included the following:

- $712.5 million of cash paid for the acquisition of Springfield;
- $473.9 million of capital expenditures, net of $6.1 million of contributions in aid of construction costs from affiliates, primarily related to plant construction and expansion at the DBM and DJ Basin complexes and the DBJV system;
- $4.0 million of cash paid for equipment purchases from Anadarko;
- $21.2 million of distributions from equity investments in excess of cumulative earnings; and
- $17.5 million of proceeds from property insurance claims attributable to the DBM outage.

Net cash used in investing activities for the year ended December 31, 2015, included the following:

- $637.5 million of capital expenditures, net of $0.5 million of contributions in aid of construction costs from affiliates, primarily related to the construction of Train IV at the DBM complex, continued construction of Lancaster Train II (within the DJ Basin complex) and expansion at the DBJV system;
- $10.9 million of cash paid for equipment purchases from Anadarko;
- $11.4 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;
- $145.6 million of net proceeds from the sale of the Dew and Pinnacle systems in East Texas; and
- $16.2 million of distributions from equity investments in excess of cumulative earnings.

Net cash used in investing activities for the year ended December 31, 2014, included the following:

- $1.5 billion of cash paid for the acquisition of DBM, net of $30.6 million of cash acquired;
- $804.8 million of capital expenditures, net of $0.2 million of contributions in aid of construction costs from affiliates, primarily related to the construction of Lancaster Trains I and II, as well as compression expansion projects, all within the DJ Basin complex;
- $356.3 million of cash paid for the acquisition of the TEFR Interests;
- $42.0 million of cash paid related to the construction of the Front Range Pipeline, which was completed in March 2014;
- $22.9 million of cash paid for equipment purchases from Anadarko;
- $10.5 million of cash paid for White Cliffs expansion projects;
- $6.6 million of cash paid related to the construction of the Texas Express Pipeline, which was completed in November 2013;
- $18.1 million of distributions from equity investments in excess of cumulative earnings; and
- $13.0 million of net proceeds, after closing adjustments, from the sale of a gathering system to a third party in September 2014.

Financing Activities. Net cash provided by financing activities for the year ended December 31, 2016, included the following:

- $599.3 million of borrowings under our RCF, net of extension costs, which were used to fund a portion of the Springfield acquisition and for general partnership purposes, including funding capital expenditures;
- $494.6 million of net proceeds from the 2026 Notes offering in July 2016, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of the outstanding borrowings under our RCF;
- $440.0 million of net proceeds from the March 2016 Series A units issuance, all of which was used to fund a portion of the acquisition of Springfield;
- $246.9 million of net proceeds from the April 2016 Series A units issuance, all of which was used to pay down amounts borrowed under our RCF in connection with the Springfield acquisition;
- $203.3 million of net proceeds from the offering of additional 2044 Notes in October 2016, after underwriting discounts and original issue premium and offering costs, all of which was used to repay amounts then outstanding under our RCF and for general partnership purposes, including capital expenditures;
- $25.0 million of net proceeds from the sale of common units to WGP, all of which was used to fund a portion of the acquisition of Springfield;
- $45.8 million of capital contribution from Anadarko related to the above-market component of swap extensions;

- $900.0 million of repayments of outstanding borrowing under our RCF;
- $671.9 million of distributions paid to our unitholders;
- $23.5 million of net distributions paid to Anadarko representing pre-acquisition intercompany transactions attributable to Springfield; and

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- $13.8 million of distributions paid to the noncontrolling interest owner of Chipeta.

Net cash used in financing activities for the year ended December 31, 2015, included the following:

- $610.0 million of repayments of outstanding borrowings under our RCF;
- $545.1 million of distributions paid to our unitholders;
- $49.8 million of net distributions paid to Anadarko representing pre-acquisition intercompany transactions attributable to Springfield and DBJV;
- $12.2 million of distributions paid to the noncontrolling interest owner of Chipeta;
- $489.6 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;
- $400.0 million of borrowings under our RCF, which were used for general partnership purposes, including funding capital expenditures;
- $57.4 million of net proceeds from sales of common units under the $500.0 million COP (as discussed in Securities within this Item 7). Net proceeds were used for general partnership purposes, including funding capital expenditures; and
- $18.4 million of capital contribution from Anadarko related to the above-market component of swap extensions.

Net cash provided by financing activities for the year ended December 31, 2014, included the following:

- $750.0 million of proceeds from the issuance of Class C units to a subsidiary of Anadarko, all of which was used to fund a portion of the acquisition of DBM;
- $603.0 million of net proceeds from the November 2014 equity offering, including net proceeds from a capital contribution by our general partner, part of which was used to fund a portion of the acquisition of DBM;
- $475.0 million of borrowings to fund a portion of the acquisition of DBM;
- $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;
- $335.0 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;
- $83.2 million of net proceeds from sales of common units under the $125.0 million COP, including net proceeds from capital contributions by our general partner;

- $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;

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- $650.0 million of repayments of outstanding borrowings under our RCF;
- $408.6 million of distributions paid to our unitholders;
- $16.4 million of net distributions to Anadarko representing intercompany transactions attributable to the acquisitions of Springfield, DBJV and the TEFR Interests; and
- $15.1 million of distributions paid to the noncontrolling interest owner of Chipeta.

Debt and credit facility. At December 31, 2016, our debt consisted of $500.0 million aggregate principal amount of the 2021 Notes, $670.0 million aggregate principal amount of the 2022 Notes, $350.0 million aggregate principal amount of the 2018 Notes, $600.0 million aggregate principal amount of the 2044 Notes, $500.0 million aggregate principal amount of the 2025 Notes, and $500.0 million aggregate principal amount of the 2026 Notes. As of December 31, 2016, the carrying value of our outstanding debt was $3.1 billion. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Senior Notes. In October 2016, we issued an additional $200.0 million in aggregate principal amount of 2044 Notes at a price to the public of 102.776% of the face amount plus accrued interest from October 1, 2016 to the settlement date. These notes were offered as additional notes under the indenture governing the 2044 Notes issued in March 2014 and are treated as a single class of securities with the 2044 Notes under such indenture. Including the effects of (i) the issuance premium for the October 2016 offering of the 2044 Notes, (ii) the issuance discount for the March 2014 offering of the 2044 Notes and (iii) the underwriting discounts, the effective interest rate of the 2044 Notes is 5.530%. Proceeds (net of underwriting discount of $1.8 million and debt issuance costs, and excluding accrued interest from October 1, 2016 to the settlement date) were used to repay amounts then outstanding under the RCF. The remaining proceeds will be used for general partnership purposes, including capital expenditures.

The 2026 Notes issued in July 2016 were offered at a price to the public of 99.796% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2026 Notes is 4.787%. Interest is paid semi-annually on January 1 and July 1 of each year. Proceeds (net of underwriting discount of $3.1 million, original issue discount and debt issuance costs) were used to repay a portion of the amount outstanding under the RCF.

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 December 31, 2016, we were in compliance with all covenants under the indentures governing our outstanding notes.

Revolving credit facility. The $1.2 billion RCF, which is expandable to a maximum of $1.5 billion, and bears interest at LIBOR, plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon our senior unsecured debt rating. In December 2016, the RCF was amended to extend the maturity date from February 2019 to February 2020. We are required to pay a quarterly facility fee currently ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), based upon our senior unsecured debt rating. As of December 31, 2016, we had no outstanding RCF borrowings and $4.9 million in outstanding letters of credit, resulting in $1.195 billion available for borrowing under the RCF. At December 31, 2016, the facility fee rate was 0.20% and we were in compliance with all covenants under the RCF.

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The RCF contains certain covenants that limit, among other things, our ability, and that of certain of our subsidiaries, to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of our business, enter into certain affiliate transactions and use proceeds other than for partnership purposes. The RCF also contains various customary covenants, customary events of default and a maximum consolidated leverage ratio as of the end of each fiscal quarter (which is defined as the ratio of consolidated indebtedness as of the last day of a fiscal quarter to Consolidated Earnings Before Interest, Taxes, Depreciation and Amortization for the most recent four consecutive fiscal quarters ending on such day) of 5.0 to 1.0, or a consolidated leverage ratio of 5.5 to 1.0 with respect to quarters ending in the 270-day period immediately following certain acquisitions. At December 31, 2016, we were in compliance with all remaining covenants under the RCF.

All notes and obligations under the RCF are recourse to our general partner. Our general partner is indemnified by wholly owned subsidiaries of Anadarko against any claims made against our general partner for our long-term debt and/or borrowings under the RCF.

In April 2016, we repaid $250.0 million of outstanding borrowings under our RCF, $246.9 million of which was funded with the proceeds from the issuance of the April 2016 Series A units. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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

Deferred purchase price obligation - Anadarko. The consideration to be paid for the March 2015 acquisition of DBJV consists of a cash payment to Anadarko due on March 31, 2020. The cash payment will be equal to (a) eight multiplied by the average of our share in the Net Earnings (see definition below) of DBJV for the calendar years 2018 and 2019, less (b) our share of all capital expenditures incurred for DBJV between March 1, 2015, and February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses and property taxes, in each case attributable to DBJV on an accrual basis. As of the acquisition date, the estimated future payment obligation (based on management's estimate of our share of forecasted Net Earnings and capital expenditures for DBJV) was $282.8 million, which had a net present value of $174.3 million, using a discount rate of 10%. During the year ended December 31, 2016, we recognized an aggregate $226.4 million decrease in the estimated future payment obligation, resulting in a net present value of $41.4 million for this obligation at December 31, 2016, calculated using a discounted cash flow model with a 10% discount rate. The reduction in the value of the deferred purchase price obligation is primarily due to revisions reflecting an increase in our estimate of aggregate capital expenditures to be incurred by DBJV through February 29, 2020, partially offset by an increase in our estimate of 2018 and 2019 Net Earnings. The accretion revision, which was recorded as a reduction to Interest expense, was $7.7 million for the year ended December 31, 2016. Accretion expense was $14.4 million and zero for the years ended December 31, 2015 and 2014, respectively. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statement on file with the SEC. We may issue common units under the $500.0 million COP, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of December 31, 2016, we had the capacity to issue additional common units with an aggregate sales price of up to $441.8 million under the $500.0 million COP. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of trades completed under the $500.0 million COP.
In March 2016, in connection with the issuance of the March 2016 Series A units, we entered into a Registration Rights Agreement with the Series A Preferred unit purchasers, pursuant to which we agreed to use our commercially reasonable efforts to file and maintain a registration statement with respect to the resale of common units that are issuable upon conversion of the Series A Preferred units. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a discussion of the Series A Preferred units.

Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. Generally, non-payment or non-performance results from a customer's inability to satisfy payables to us for services rendered or volumes owed pursuant to gas imbalance agreements. We examine and monitor the creditworthiness of third-party customers and may establish credit limits for third-party customers. A substantial portion of our throughput, however, comes from producers that have investment-grade ratings.
We are dependent upon a single producer, Anadarko, for a substantial portion of our volumes (excluding our equity investment throughput), and we do not maintain a credit limit with respect to Anadarko. Consequently, we are subject to the risk of non-payment or late payment by Anadarko for gathering, processing and transportation fees and for proceeds from the sale of residue, NGLs and condensate to Anadarko.
We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko. We are also party to agreements with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes with respect to the assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, and are subject to performance risk thereunder. See Risk Factors under Part I, Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
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.

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CONTRACTUAL OBLIGATIONS

The following is a summary of our contractual cash obligations as of December 31, 2016. The table below excludes amounts classified as current liabilities on the consolidated balance sheets, other than the current portions of the categories listed within the table. It is expected that the majority of the excluded current liabilities will be paid in cash in 2017.

	Obligations by Period						
thousands	2017	2018	2019	2020	2021	Thereafter	Total
Long-term debt							
Principal	$—	$350,000	$—	$—	$500,000	$2,270,000	$3,120,000
Interest	138,475	135,026	129,375	129,375	112,727	934,645	1,579,623
Asset retirement obligations	3,114	—	395	—	1,564	137,334	142,407
Capital expenditures	50,935	—	—	—	—	—	50,935
Credit facility fees	2,400	2,400	2,400	375	—	—	7,575
Environmental obligations	630	452	452	302	302	32	2,170
Operating leases	7,322	898	764	122	—	—	9,106
Deferred purchase price obligation - Anadarko	—	—	—	56,455	—	—	56,455
Total	$202,876	$488,776	$133,386	$186,629	$614,593	$3,342,011	$4,968,271

Credit facility fees. For additional information on credit facility fees required under our RCF, see Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Asset retirement obligations. When assets are acquired or constructed, the initial estimated asset retirement obligation is recognized in an amount equal to the net present value of the settlement obligation, with an associated increase in properties and equipment. Revisions to estimated asset retirement obligations can result from revisions to estimated inflation rates and discount rates, changes in retirement costs and the estimated timing of settlement. For additional information, see Note 11—Asset Retirement Obligations in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Capital expenditures. Included in this amount are capital obligations related to our expansion projects. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual obligations made in advance of the actual expenditures. See Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Environmental obligations. We are subject to various environmental-remediation obligations arising from federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. We regularly monitor the remediation and reclamation process and the liabilities recorded and believe that the amounts reflected in our recorded environmental obligations are adequate to fund remedial actions to comply with present laws and regulations. For additional information on environmental obligations, see Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Operating leases. Anadarko, on our behalf, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting our operations, for which it charges us rent. The amounts above represent existing contractual operating lease obligations that may be assigned or otherwise charged to us pursuant to the reimbursement provisions of the omnibus agreement. See Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

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Deferred purchase price obligation - Anadarko. We acquired Anadarko's interest in DBJV in March 2015. 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 $56.5 million. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

For additional information on contracts, obligations and arrangements we enter into from time to time, see Note 5—Transactions with Affiliates and Note 13—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of consolidated financial statements in accordance with GAAP requires our management to make informed judgments and estimates that affect the amounts of assets and liabilities as of the date of the financial statements and affect the amounts of revenues and expenses recognized during the periods reported. On an ongoing basis, management reviews its estimates, including those related to the determination of property, plant and equipment, asset retirement obligations, litigation, environmental liabilities, income taxes and fair values. Although these estimates are based on management's best available knowledge of current and expected future events, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment and discusses the selection and development of these estimates with the Audit Committee of our general partner. For additional information concerning our accounting policies, see Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Depreciation. Depreciation expense is generally computed using the straight-line method over the estimated useful life of the assets. Determination of depreciation expense requires judgment regarding the estimated useful lives and salvage values of property, plant and equipment. As circumstances warrant, depreciation estimates are reviewed to determine if any changes in the underlying assumptions are necessary. The weighted-average life of our long-lived assets is 24 years. If the depreciable lives of our assets were reduced by 10%, we estimate that annual depreciation expense would increase by $30.4 million, which would result in a corresponding reduction in our operating income (loss).

Impairments of tangible assets. Property, plant and equipment are generally stated at the lower of historical cost less accumulated depreciation or fair value, if impaired. Because acquisitions of assets from Anadarko are transfers of net assets between entities under common control, the Partnership assets acquired by us from Anadarko are initially recorded at Anadarko's historic carrying value. Assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. Property, plant and equipment balances are evaluated for potential impairment when events or changes in circumstances indicate that their carrying amounts may not be recoverable from expected undiscounted cash flows from the use and eventual disposition of an asset. If the carrying amount of the asset is not expected to be recoverable from future undiscounted cash flows, an impairment may be recognized. Any impairment is measured as the excess of the carrying amount of the asset over its estimated fair value.
In assessing long-lived assets for impairments, our management evaluates changes in our business and economic conditions and their implications for recoverability of the assets' carrying amounts. Since a significant portion of our revenues arises from gathering, processing and transporting the natural gas production from Anadarko-operated properties, significant downward revisions in reserve estimates or changes in future development plans by Anadarko, to the extent they affect our operations, may necessitate assessment of the carrying amount of our affected assets for recoverability. Such assessment requires application of judgment regarding the use and ultimate disposition of the asset, long-range revenue and expense estimates, global and regional economic conditions, including commodity prices and drilling activity by our customers, as well as other factors affecting estimated future net cash flows. The measure of impairments to be recognized, if any, depends upon management's estimate of the asset's fair value, which

may be determined based on the estimates of future net cash flows or values at which similar assets were transferred in the market in recent transactions, if such data is available. See Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K for a description of impairments recorded during the years ended December 31, 2016, 2015 and 2014.

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Impairments of goodwill. Goodwill is recorded when the purchase price of a business acquired exceeds the fair market value of the tangible and separately measurable intangible net assets. In addition, our goodwill represents the allocated portion of Anadarko's midstream goodwill attributed to the Partnership assets acquired from Anadarko. The carrying value of Anadarko's midstream goodwill represents the excess of the purchase price paid to a third-party entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, our allocated goodwill balance does not represent, and in some cases is significantly different from, the difference between the consideration paid by us for acquisitions from Anadarko and the fair value of such net assets on their respective acquisition dates.

We evaluate whether goodwill has been impaired annually as of October 1, unless facts and circumstances make it necessary to test more frequently. Accounting standards require that goodwill be assessed for impairment at the reporting unit level. Management has determined that we have one operating segment and two reporting units: (i) gathering and processing and (ii) transportation. The carrying value of goodwill as of December 31, 2016, was $412.8 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. We allocated $1.6 million of goodwill to our divestiture of the Hugoton system upon sale in October 2016 and $5.1 million of goodwill to our divestiture of the Dew and Pinnacle systems upon sale in July 2015. See Note 2—Acquisitions and Divestitures in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

The first step in assessing whether an impairment of goodwill is necessary is a qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is less than its carrying amount, including goodwill. If we conclude it is more likely than not that the fair value of the reporting unit exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment indicates the fair value of the reporting unit may be less than its carrying amount, we would compare the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determine whether an impairment is necessary.

When evaluating whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, we assess relevant events and circumstances, including the following:

- significant changes in our unit price;
- significant declines in commodity prices;
- significant increases in operating and capital costs;
- impairments recognized;
- acquisitions and disposals of assets;
- changes in throughput; and
- significant declines in trading multiples for our peers.

In this manner, estimating the fair value of our reporting units was not necessary based on the qualitative evaluation as of October 1, 2016. Procedures were also performed in the fourth quarter of 2016 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices, and we concluded that estimating the fair value of our reporting units was not necessary at that time either. However, fair-value estimates of our reporting units may be required for goodwill impairment testing in the future, and if the carrying amount of a reporting unit exceeds its fair value, goodwill is written down to the implied fair value through a charge to operating expense based on a hypothetical purchase price allocation.

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Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management uses information available to make these fair-value estimates, including market multiples of EBITDA. Specifically, our management estimates fair value by applying an estimated multiple to projected EBITDA. Management considered observable transactions in the market, as well as trading multiples for peers, to determine an appropriate multiple to apply against our projected EBITDA. A lower fair-value estimate in the future for any of our reporting units could result in a goodwill impairment. Factors that could trigger a lower fair-value estimate include sustained price declines, throughput declines, cost increases, regulatory or political environment changes, and other changes in market conditions such as decreased prices in market-based transactions for similar assets. Based on our most recent goodwill impairment test, we concluded, based on a qualitative assessment, that it is more likely than not that the fair value of each reporting unit exceeded the carrying value of the reporting unit. Therefore, no goodwill impairment was indicated, and no goodwill impairment has been recognized in our consolidated financial statements.

Impairments of intangible assets. Our intangible asset balance as of December 31, 2016 and 2015, primarily represents the fair value, net of amortization, of (i) contracts we assumed in connection with the Platte Valley acquisition in February 2011, which are being amortized on a straight-line basis over 50 years, (ii) interconnect agreements at Chipeta entered into in November 2012, which are being amortized on a straight-line basis over 10 years, and (iii) contracts we assumed in connection with the DBM acquisition in November 2014, which are being amortized on a straight-line basis over 30 years. See Note 2—Acquisitions and Divestitures and Note 8—Goodwill and Intangibles in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
Management assesses intangible assets for impairment together with the related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Impairments exist when the carrying amount of an asset exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset’s carrying amount over its estimated fair value, such that the asset’s carrying amount is adjusted to its estimated fair value with an offsetting charge to impairment expense. No intangible asset impairment has been recognized in connection with these assets.

Fair value. Management estimates fair value in performing impairment tests for long-lived assets and goodwill as well as for the initial measurement of asset retirement obligations and the initial recognition of environmental obligations assumed in third-party acquisitions. When our management is required to measure fair value and there is not a market-observable price for the asset or liability or a market-observable price for a similar asset or liability, management utilizes the cost, income, or market multiples valuation approach depending on the quality of information available to support management’s assumptions. The cost approach is based on management’s best estimate of the current asset replacement cost. The income approach uses management’s best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk adjusted discount rate. Such evaluations involve a significant amount of judgment, since the results are based on expected future events or conditions, such as sales prices, estimates of future throughput, capital and operating costs and the timing thereof, economic and regulatory climates and other factors. A multiple approach uses management’s best assumptions regarding expectations of projected EBITDA and the multiple of that EBITDA that a buyer would pay to acquire an asset. Management’s estimates of future net cash flows and EBITDA are inherently imprecise because they reflect management’s expectation of future conditions that are often outside of management’s control. However, assumptions used reflect a market participant’s view of long-term prices, costs and other factors, and are consistent with assumptions used in our business plans and investment decisions.

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OFF-BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements other than operating leases and standby letters of credit. The information pertaining to operating leases and our standby letters of credit required for this item is provided under Note 13—Commitments and Contingencies and Note 12—Debt and Interest Expense, respectively, included in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

RECENT ACCOUNTING DEVELOPMENTS

See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity price risk. Certain of our processing services are provided under percent-of-proceeds and keep-whole agreements in which Anadarko is typically responsible for the marketing of the natural gas, condensate and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of residue and/or NGLs. Under keep-whole agreements, we keep 100% of the NGLs produced and the processed natural gas, or value of the natural gas, is returned to the producer, and since some of the gas is used and removed during processing, we compensate the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas used.
To mitigate our exposure to a majority of the commodity price risk inherent in our percent-of-proceeds and keep-whole contracts, we currently have in place commodity price swap agreements with Anadarko covering activity at our DJ Basin complex and the MGR assets. On December 1, 2016, we renewed these commodity price swap agreements through December 31, 2017, with an effective date of January 1, 2017. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Part II, Item 8 of this Form 10-K.
We consider our exposure to commodity price risk associated with the above-described arrangements to be minimal given the existence of the commodity price swap agreements with Anadarko and the relatively small amount of our operating income (loss) that is impacted by changes in market prices. Accordingly, we do not expect that a 10% increase or decrease in commodity prices would have a material impact on our operating income (loss), financial condition or cash flows for the next twelve months, excluding the effect of imbalances described below.
We bear a limited degree of commodity price risk with respect to settlement of our natural gas imbalances that arise from differences in gas volumes received into our systems and gas volumes delivered by us to customers, as well as instances where our actual liquids recovery or fuel usage varies from the contractually stipulated amounts. Natural gas volumes owed to or by us that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates, and generally reflect market index prices. Other natural gas volumes owed to or by us are valued at our weighted-average cost of natural gas as of the balance sheet dates and are settled in-kind. Our exposure to the impact of changes in commodity prices on outstanding imbalances depends on the timing of settlement of the imbalances.

Interest rate risk. Interest rates remained at or near historic lows during 2016. In December 2016, the Federal Open Market Committee raised the target range for the federal funds rate from 1/4 to 1/2 percent to 1/2 to 3/4 percent, representing the second federal funds rate increase in a decade. This increase, and any future increases, in the federal funds rate will ultimately result in an increase in our financing costs. As of December 31, 2016, we had no outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). A 10% change in LIBOR would have resulted in no change in net income (loss) and the fair value of the borrowings under the RCF at December 31, 2016.
We may incur additional variable-rate debt in the future, either under our RCF or other financing sources, including commercial bank borrowings or debt issuances.

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Item 8. Financial Statements and Supplementary Data

WESTERN GAS PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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WESTERN GAS PARTNERS, LP

REPORT OF MANAGEMENT

Management of Western Gas Partners, LP’s (the “Partnership”) general partner prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the Partnership’s financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States (“GAAP”). In preparing its consolidated financial statements, the Partnership includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Partnership’s consolidated financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Partnership’s financial records and related data, as well as the minutes of the Directors’ meetings.

MANAGEMENT’S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Partnership’s internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2016. This assessment was based on criteria established in the Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on our assessment using the COSO criteria, we concluded the Partnership’s internal control over financial reporting was effective as of December 31, 2016.

KPMG LLP, the Partnership’s independent registered public accounting firm, has issued an attestation report on the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2016.

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

February 23, 2017

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Western Gas Holdings, LLC (as general partner of Western Gas Partners, LP):

We have audited Western Gas Partners, LP's (the Partnership) internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Western Gas Partners, LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Western Gas Partners, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Western Gas Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated February 23, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 23, 2017

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WESTERN GAS PARTNERS, LP

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Unitholders
Western Gas Holdings, LLC (as general partner of Western Gas Partners, LP):

We have audited the accompanying consolidated balance sheets of Western Gas Partners, LP (the Partnership) and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Western Gas Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Western Gas Partners, LP's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 23, 2017 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 23, 2017

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
thousands except per-unit amounts	2016	2015	2014
Revenues and other – affiliates			
Gathering, processing and transportation	$750,087	$772,361	$615,907
Natural gas and natural gas liquids sales	478,145	447,106	582,989
Other	—	1,172	5,078
Total revenues and other – affiliates	1,228,232	1,220,639	1,203,974
Revenues and other – third parties			
Gathering, processing and transportation	477,762	356,477	278,127
Natural gas and natural gas liquids sales	94,168	170,843	42,916
Other	4,108	4,113	8,360
Total revenues and other – third parties	576,038	531,433	329,403
Total revenues and other	1,804,270	1,752,072	1,533,377
Equity income, net – affiliates	78,717	71,251	57,836
Operating expenses			
Cost of product [(1)]	494,194	528,369	458,379
Operation and maintenance [(1)]	308,010	331,972	293,710
General and administrative [(1)]	45,591	41,319	38,561
Property and other taxes	40,145	33,288	28,889
Depreciation and amortization	272,933	272,611	211,809
Impairments	15,535	515,458	5,125
Total operating expenses	1,176,408	1,723,017	1,036,473
Gain (loss) on divestiture and other, net [(2)]	(14,641)	57,024	(9)
Proceeds from business interruption insurance claims	16,270	—	—
Operating income (loss)	708,208	157,330	554,731
Interest income – affiliates	16,900	16,900	16,900
Interest expense [(3)]	(114,921)	(113,872)	(76,766)
Other income (expense), net	479	(619)	864
Income (loss) before income taxes	610,666	59,739	495,729
Income tax (benefit) expense	8,372	45,532	39,061
Net income (loss)	602,294	14,207	456,668
Net income attributable to noncontrolling interest	10,963	10,101	14,025
Net income (loss) attributable to Western Gas Partners, LP	$591,331	$4,106	$442,643
Limited partners' interest in net income (loss):			
Net income (loss) attributable to Western Gas Partners, LP	$591,331	$4,106	$442,643
Pre-acquisition net (income) loss allocated to Anadarko	(11,326)	(79,386)	(65,154)
Series A Preferred units interest in net (income) loss [(4)]	(76,893)	—	—
General partner interest in net (income) loss [(4)]	(236,561)	(180,996)	(120,980)
Common and Class C limited partners' interest in net income (loss) [(4)]	266,551	(256,276)	256,509
Net income (loss) per common unit – basic [(5)]	$1.74	$(1.95)	$2.13
Net income (loss) per common unit – diluted [(5)]	1.74	(1.95)	2.12

(1) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $80.5 million, $167.4 million and $127.9 million for the years ended December 31, 2016, 2015 and 2014, respectively. Operation and maintenance includes charges from Anadarko of $72.3 million, $77.1 million and $71.4 million for the years ended December 31, 2016, 2015 and 2014, respectively. General and administrative includes charges from Anadarko of

$38.1 million, $33.9 million and $31.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. See Note 5.

(2) Includes losses related to an incident at the DBM complex for the year ended December 31, 2015. See Note 1.

(3) Includes affiliate (as defined in Note 1) amounts of $7.7 million, $(14.4) million and zero for the years ended December 31, 2016, 2015 and 2014, respectively. See Note 2 and Note 12.

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

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

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

thousands except number of units	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$357,925	$98,033
Accounts receivable, net (1)	223,223	193,329
Other current assets	12,866	7,855
Total current assets	594,014	299,217
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	6,861,942	6,556,778
Less accumulated depreciation	1,812,010	1,697,999
Net property, plant and equipment	5,049,932	4,858,779
Goodwill	417,610	419,186
Other intangible assets	803,698	832,127
Equity investments	594,208	618,887
Other assets	13,566	13,001
Total assets	$7,733,028	$7,301,197
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and imbalance payables	$123,285	$98,661
Accrued ad valorem taxes	23,121	17,808
Accrued liabilities	168,899	119,019
Total current liabilities	315,305	235,488
Long-term debt	3,091,461	2,690,651
Deferred income taxes	6,402	139,704
Asset retirement obligations and other	142,641	128,652
Deferred purchase price obligation – Anadarko (2)	41,440	188,674
Total long-term liabilities	3,281,944	3,147,681
Total liabilities	3,597,249	3,383,169
Equity and partners' capital		
Series A Preferred units (21,922,831 and zero units issued and outstanding at December 31, 2016 and 2015, respectively) (3)	639,545	—
Common units (130,671,970 and 128,576,965 units issued and outstanding at December 31, 2016 and 2015, respectively)	2,536,872	2,588,991
Class C units (12,358,123 and 11,411,862 units issued and outstanding at December 31, 2016 and 2015, respectively) (4)	750,831	710,891
General partner units (2,583,068 units issued and outstanding at December 31, 2016 and 2015)	143,968	120,164
Net investment by Anadarko	—	430,598
Total partners' capital	4,071,216	3,850,644
Noncontrolling interest	64,563	67,384
Total equity and partners' capital	4,135,779	3,918,028
Total liabilities, equity and partners' capital	$7,733,028	$7,301,197

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $76.6 million and $42.7 million as of December 31, 2016 and 2015, respectively. Accounts receivable, net as of December 31, 2016

and 2015, also includes an insurance claim receivable related to an incident at the DBM complex. See Note 1.

(2) See Note 2.

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

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

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF EQUITY AND PARTNERS' CAPITAL

	Partners' Capital						
thousands	Net Investment by Anadarko	Common Units	Class C Units	Series A Preferred Units	General Partner Units	Noncontrolling Interest	Total
Balance at December 31, 2013	$842,731	$2,431,193	$—	$—	$78,157	$ 70,594	$3,422,675
Net income (loss)	65,154	254,737	1,772	—	120,980	14,025	456,668
Issuance of common and general partner units, net of offering expenses	—	691,417	—	—	13,311	—	704,728
Issuance of Class C units	—	—	750,000	—	—	—	750,000
Beneficial conversion feature of Class C units	—	34,815	(34,815)	—	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(15,149)	(15,149)
Distributions to unitholders	—	(302,049)	—	—	(106,572)	—	(408,621)
Acquisitions from affiliates	(372,784)	16,534	—	—	—	—	(356,250)
Contributions of equity-based compensation from Anadarko	—	3,104	—	—	63	—	3,167
Net pre-acquisition contributions from (distributions to) Anadarko (1)	(16,692)	—	—	—	—	—	(16,692)
Net distributions to Anadarko of other assets	—	(10,492)	—	—	(214)	—	(10,706)
Elimination of net deferred tax liabilities	38,160	—	—	—	—	—	38,160
Other	27	455	—	—	—	—	482
Balance at December 31, 2014	$556,596	$3,119,714	$716,957	$—	$105,725	$ 69,470	$4,568,462
Net income (loss)	79,386	(238,166)	(18,110)	—	180,996	10,101	14,207
Above-market component of swap extensions with Anadarko (2)	—	18,449	—	—	—	—	18,449
Issuance of common units, net of offering expenses	—	57,353	—	—	—	—	57,353
Amortization of beneficial conversion feature of Class C units	—	(12,044)	12,044	—	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(12,187)	(12,187)
Distributions to unitholders	—	(378,602)	—	—	(166,541)	—	(545,143)
Acquisitions from affiliates	(197,562)	23,286	—	—	—	—	(174,276)
Contributions of equity-based compensation from Anadarko	—	3,480	—	—	71	—	3,551

Net pre-acquisition contributions from (distributions to) Anadarko	(49,801)	—	—	—	—	—	(49,801)
Net distributions to Anadarko of other assets	—	(4,547)	—	—	(85)	—	(4,632)
Elimination of net deferred tax liabilities	41,844	—	—	—	—	—	41,844
Other	135	68	—	—	(2)	—	201
Balance at December 31, 2015	$430,598	$2,588,991	$710,891	$—	$120,164	$ 67,384	$3,918,028
Net income (loss)	11,326	269,018	28,642	45,784	236,561	10,963	602,294
Above-market component of swap extensions with Anadarko [(2)]	—	45,820	—	—	—	—	45,820
Issuance of common units, net of offering expenses	—	25,000	—	—	—	—	25,000
Issuance of Series A Preferred units, net of offering expenses	—	—	—	686,937	—	—	686,937
Beneficial conversion feature of Series A Preferred units	—	93,409	—	(93,409)	—	—	—
Amortization of beneficial conversion feature of Class C units and Series A Preferred units	—	(42,407)	11,298	31,109	—	—	—
Distributions to noncontrolling interest owner	—	—	—	—	—	(13,784)	(13,784)
Distributions to unitholders	—	(428,231)	—	(30,876)	(212,831)	—	(671,938)
Acquisitions from affiliates	(553,833)	(158,667)	—	—	—	—	(712,500)
Revision to Deferred purchase price obligation – Anadarko [(3)]	—	139,487	—	—	—	—	139,487
Contributions of equity-based compensation from Anadarko	—	4,131	—	—	83	—	4,214
Net pre-acquisition contributions from (distributions to) Anadarko	(23,491)	—	—	—	—	—	(23,491)
Net distributions to Anadarko of other assets	—	(572)	—	—	(9)	—	(581)
Elimination of net deferred tax liabilities	135,400	—	—	—	—	—	135,400
Other	—	893	—	—	—	—	893
Balance at December 31, 2016	$—	$2,536,872	$750,831	$639,545	$143,968	$ 64,563	$4,135,779

(1) Includes deferred taxes on capitalized interest of $0.3 million associated with the acquisition of the TEFR Interests (as defined and described in Note 1).

(2) See Note 5.

(3) See Note 2.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
thousands	2016	2015	2014
Cash flows from operating activities			
Net income (loss)	$602,294	$14,207	$456,668
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	272,933	272,611	211,809
Impairments	15,535	515,458	5,125
Non-cash equity-based compensation expense	4,735	4,188	3,920
Deferred income taxes	2,555	11,346	38,682
Accretion and amortization of long-term obligations, net	(3,789)	17,698	2,736
Equity income, net – affiliates	(78,717)	(71,251)	(57,836)
Distributions from equity investment earnings – affiliates	82,185	82,054	62,967
(Gain) loss on divestiture and other, net (1)	14,641	(57,024)	9
Lower of cost or market inventory adjustments	168	443	—
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	(48,947)	(4,371)	1,399
Increase (decrease) in accounts and imbalance payables and accrued liabilities, net	58,359	1,006	(34,980)
Change in other items, net	(4,367)	(720)	3,996
Net cash provided by operating activities	917,585	785,645	694,495
Cash flows from investing activities			
Capital expenditures	(479,993)	(637,964)	(805,005)
Contributions in aid of construction costs from affiliates	6,135	461	183
Acquisitions from affiliates	(716,465)	(10,903)	(379,193)
Acquisitions from third parties	—	(3,514)	(1,523,327)
Investments in equity affiliates	(27)	(11,442)	(64,278)
Distributions from equity investments in excess of cumulative earnings – affiliates	21,238	16,244	18,055
Proceeds from the sale of assets to affiliates	623	925	402
Proceeds from the sale of assets to third parties	45,490	145,916	12,988
Proceeds from property insurance claims	17,465	—	—
Net cash used in investing activities	(1,105,534)	(500,277)	(2,740,175)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	1,297,218	889,606	1,646,878
Repayments of debt	(900,000)	(610,000)	(650,000)
Increase (decrease) in outstanding checks	2,079	(2,666)	765
Proceeds from the issuance of common and general partner units, net of offering expenses	25,000	57,353	704,489
Proceeds from the issuance of Class C units	—	—	750,000
Proceeds from the issuance of Series A Preferred units, net of offering expenses	686,937	—	—
Distributions to unitholders (2)	(671,938)	(545,143)	(408,621)
Distributions to noncontrolling interest owner	(13,784)	(12,187)	(15,149)
Net contributions from (distributions to) Anadarko	(23,491)	(49,801)	