Western Gas Partners LP
Form 10-K
February 26, 2015
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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, 2014

Or

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

For the transition period from to

Commission file number: 001-34046

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

Delaware	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 o

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 o 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 o

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

Indicate by check mark 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. o

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

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

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

The aggregate market value of the registrant's common units representing limited partner interests held by non-affiliates of the registrant was $5.2 billion on June 30, 2014, based on the closing price as reported on the New York Stock Exchange.

At February 23, 2015, there were 127,695,130 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
None

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DEFINITIONS

As generally used within the energy industry and in this Form 10-K, the identified terms have the following meanings:

Backhaul: Pipeline transportation service in which the nominated gas flow from delivery point to receipt point is in the opposite direction as the pipeline's physical gas flow.

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

Bbls/d: Barrels per day.

Bcf: One billion cubic feet.

Bcf/d: One billion cubic feet per day.

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

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

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

Delivery point: The point where gas or natural gas liquids 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.

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.

End-use markets: The ultimate users/consumers of transported energy products.

Frac: The process of hydraulic fracturing, or the injection of fluids into the wellbore to create fractures in rock formations, stimulating the production of oil or gas.

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.

Forward-haul: Pipeline transportation service in which the nominated gas flow from receipt point to delivery point is in the same direction as the pipeline's physical gas flow.

Gpm: Gallons per minute, when used in the context of amine treating capacity.

Hinshaw pipeline: A pipeline that has received exemptions from regulations pursuant to the Natural Gas Act. These pipelines transport interstate natural gas not subject to regulations under the Natural Gas Act.

Imbalance: Imbalances result from (i) differences between gas volumes nominated by customers and gas volumes received from those customers and (ii) differences between gas volumes received from customers and gas volumes delivered to those customers.

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Joule-Thompson (JT) plant: 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.
MBbls/d: One thousand barrels per day.
MMBtu: One million British thermal units.
MMBtu/d: One million British thermal units per day.
MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
Natural gas liquid(s) or NGL(s): The combination of ethane, propane, normal butane, isobutane and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
Play: A group of gas or oil fields that contain known or potential commercial amounts of petroleum and/or natural gas.
Receipt point: The point where volumes are received by or into a gathering system, processing facility or transportation pipeline.
Refrigeration plant: a method of processing natural gas by reducing the gas temperature with the use of an external refrigeration system.
Residue: The natural gas remaining after the unprocessed natural gas stream has been processed or treated.
Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.
Stabilization: The process of separating very light hydrocarbon gases, methane and ethane in particular, from heavier hydrocarbon components. This process reduces the volatility of condensates/crude oil during transportation and storage. Typically, stabilized condensate / oil has a vapor pressure of less than 11 pounds per square inch, absolute, and a Reid Vapor Pressure of less than 10 pounds per square inch.
Tailgate: The point at which processed natural gas and/or natural gas liquids leave a processing facility for end-use markets.
Wellhead: The point at which the hydrocarbons and water exit the ground.

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PART I

Items 1 and 2. Business and Properties

GENERAL OVERVIEW

Western Gas Partners, LP, a growth-oriented Delaware master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007 to own, operate, acquire and develop midstream energy assets, closed its initial public offering ("IPO") to become publicly traded in 2008. For purposes of this report, the "Partnership," "we," "our," "us" or like ter refers to Western Gas Partners, LP and its subsidiaries. We are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko Petroleum Corporation and its consolidated subsidiaries, as well as third-party producers and customers. Our common units are publicly traded on the New York Stock Exchange ("NYSE") under the symbol "WES."
The Partnership's general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation in September 2012 to own our general partner, as well as a significant limited partner interest in us. WGP's common units are publicly traded on the NYSE under the symbol "WGP." Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. "Equity investment throughput" refers to our 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 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. "MIGC" refers to MIGC LLC, and "Chipeta" refers to Chipeta Processing LLC. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.

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 U.S. Securities and Exchange Commission ("SEC") under the Securities Exchange Act of 1934, as amended. 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 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 general partner's 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, 2014, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	1	5	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	13	3	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipeline	1	—	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas. The following table provides information regarding our assets by geographic region, as of and for the year ended December 31, 2014, excluding Train II at our Lancaster plant which is currently under construction in Northeast Colorado and Train IV at the DBM complex, which is currently preparing for construction in West Texas and was acquired with the acquisition of DBM (see Acquisitions below and Assets Under Development within these Items 1 and 2):

Area	Asset Type	Miles of Pipeline (1)	Approximate Number of Active Receipt Points (1)	Gas Compression (HP) (1)	Processing or Treating Capacity (MMcf/d) (1) (2)	Average Gathering, Processing and Transportation Throughput (MMcf/d) (3)	Average Gathering, Processing and Transportation Throughput (MBbls/d) (4)
Rocky Mountains	Gathering, Processing and Treating	7,732	5,044	482,108	3,161	2,258	—
	Transportation	1,037	41	28,002	—	99	35
Mid-Continent	Gathering	2,067	1,498	90,214	—	66	—
North-central Pennsylvania	Gathering	632	368	70,750	—	805	—
Texas	Gathering, Processing and Treating	1,060	1,017	61,000	1,000	430	—
	Transportation	1,145	12	34,395	—	—	81
Total		13,673	7,980	766,469	4,161	3,658	116

(1) All system metrics are presented on a gross basis.

(2) Capacity excludes 170 MBbls/d of fractionation capacity attributable to the Mont Belvieu JV.

(3) Includes 100% of Chipeta throughput, 50% of Newcastle throughput, 22% of Rendezvous throughput and 14.81% of Fort Union throughput.

(4) Represents total throughput measured in barrels, consisting of throughput from our Chipeta NGL pipeline, our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEG and TEP throughput and our 33.33% share of average FRP throughput. See Properties below for further descriptions of these systems.

Our operations are organized into a single operating segment that engages in gathering, processing, compressing, treating and transporting Anadarko and third-party natural gas, condensate, NGLs and crude oil in the United States. See Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2014, 2013 and 2012.

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ACQUISITIONS

Acquisitions. The following table presents our acquisitions during 2014, and identifies the funding sources for such acquisitions. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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

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

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

(3) See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for a discussion of the Class C units.

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 Item 8 of this Form 10-K) by us as of December 31, 2014. 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 in the Notes to Consolidated Financial Statements under 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

Equity offerings. We completed the following public equity offerings during 2014:

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued [1]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
Continuous Offering Program - 2014 [2]	1,133,384	23,132	$73.48	$1,738	$83,245
November 2014 equity offering [3]	8,620,153	153,061	70.85	18,583	602,999

(1)

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

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

(3) Includes the issuance of 1,120,153 common units pursuant to the partial exercise of the underwriters' over-allotment option. Net proceeds from this partial exercise were $77.0 million. Beginning with this partial exercise, our general partner elected not to make a corresponding capital contribution to maintain a 2.0% interest in us. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Other equity offerings. In November 2014, we issued 10,913,853 Class C units to a subsidiary of Anadarko at an implied price of $68.72 per unit, generating proceeds of $750.0 million, all of which was used to fund a portion of the acquisition of DBM. See Note 3—Partnership Distributions and Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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:

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

- 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 existing infrastructure, operating expertise and customer relationships by constructing and expanding systems to meet new or increased demand of our services.

- Attracting third-party volumes to our systems. We expect to 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 substantial majority of the commodity price uncertainty through the use of fee-based contracts and fixed-price hedges.

- Maintaining investment grade ratings. We intend to operate at appropriate leverage and distribution coverage levels in line with other partnerships in our sector that have received investment grade credit ratings. By maintaining an investment grade credit rating with all three credit rating agencies, 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 their 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.

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- Relatively stable and predictable cash flows. Our cash flows are largely protected from fluctuations caused by commodity price volatility due to (i) the approximately 80% of our services that are provided pursuant 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 substantial majority of our percent-of-proceeds and keep-whole contracts. For the year ended December 31, 2014, 99% of our 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. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

- Financial flexibility to pursue expansion and acquisition opportunities. We believe our operating cash flows, borrowing capacity, and access to debt and equity capital markets provide us with the financial flexibility to competitively pursue acquisition and expansion opportunities and to execute our strategy across capital market cycles. We currently have investment grade ratings from all three of the major rating agencies and, as of December 31, 2014, we had $510.0 million of outstanding borrowings and $12.8 million in outstanding letters of credit issued under our $1.2 billion senior unsecured revolving credit facility (“RCF”).

- Substantial presence in basins with historically strong producer economics. Certain of our gathering and processing systems and facilities, such as the DBM complex, the DJ Basin complex and the Brasada complex serve production in liquids-rich growth areas where the hydrocarbon production contains not only natural gas, but also oil, condensate, and significant amounts of NGLs. Production in liquids-rich areas offers our customers higher margins and superior economics compared to basins in which the gas is predominantly dry. In addition, our interests in the Anadarko-Operated and Non-Operated Marcellus gathering systems serve dry gas production from the Marcellus shale, which historically has provided attractive producer returns due to the overall scale and quality of the underlying resource, as well as its access to premium markets in the northeast United States. See Properties below for further asset descriptions.

- Well-positioned, well-maintained and efficient 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 includes an integrated package of high-quality, well-maintained assets for which we have implemented modern processing, treating, measuring and operating technologies.

- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed nine related-party acquisitions and six third-party acquisitions, with an aggregate value of $4.8 billion. 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, please read Risk Factors under 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, 2014, 48% of our gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko, and 57% of our processing throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko. In addition, with respect to the Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems, Anadarko has made a dedication 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, 2014, WGP held 49,296,205 of our common units, representing a 34.9% limited partner interest in us, and, through its ownership of our general partner, indirectly held 2,583,068 general partner units, representing a 1.8% general partner interest in us, and 100% of our incentive distribution rights ("IDRs"). As of December 31, 2014, other subsidiaries of Anadarko held 757,619 common units and 10,913,853 Class C units, representing an aggregate 8.3% limited partner interest in us. As of December 31, 2014, the public held 77,641,306 common units, representing a 55.0% limited partner interest in us.

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. 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. Please see Risk Factors under Item 1A and Certain Relationships and Related Transactions, and Director Independence under Item 13 of this Form 10-K for more information.

INDUSTRY OVERVIEW

The midstream natural gas industry is the link between the exploration for and production of natural gas and the delivery of the resulting hydrocarbon components to end-use markets. Operators within this industry create value at various stages along the natural gas value chain by gathering raw natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs, and then routing the separated dry gas and NGL streams for delivery to end-use markets or to the next intermediate stage of the value chain.
The following diagram illustrates the primary groups of assets found along the natural gas value chain:

Service Types

The services provided by us and other midstream natural gas companies are generally classified into the categories described below. As indicated below, we do not currently provide all of these services, although we may do so in the future.

- 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. In connection with our gathering services, we sometimes retain, stabilize and sell drip condensate, which falls out of the natural gas stream during gathering. Stabilization is a process that separates the heavier hydrocarbons (which also serve as valuable commodities) 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. We provide stabilization for condensate at many of our processing plants (such as the DJ Basin and Brasada complexes).

- 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. Processing separates the heavier and more valuable hydrocarbon components, which are extracted as NGLs, from the remaining residue. The remaining residue is then designated for long-haul pipeline transportation or commercial use.

- 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.

Typical Contractual Arrangements

Midstream natural gas 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 are described below:

- Fee-based. Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered, treated and/or processed 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 and/or NGLs or a percentage of the actual residue 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.

Two forms of contracts are used in the transportation of natural gas, NGLs and crude oil, as described below:

- Firm. Firm transportation service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. 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 a usage fee based on the amount of natural gas transported.

- Interruptible. Interruptible transportation 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 of gas actually 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 on the pipeline.

See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for information regarding 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, 2014.

GATHERING, PROCESSING AND TREATING

Overview - Rocky Mountains - Wyoming

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Northeast Wyoming	Bison	Treating	1	450	—	14,320	—	—
Northeast Wyoming	Fort Union [(1)]	Gathering & Treating	1	294	—	5,454	1	318
Northeast Wyoming	Hilight	Gathering & Processing	1	60	13	37,357	1	1,563
Northeast Wyoming	Newcastle [(1)]	Gathering & Processing	1	3	1	2,660	1	180
Southwest Wyoming	Granger complex [(2)]	Gathering & Processing	2	500	8	43,950	1	896
Southwest Wyoming	Red Desert complex [(3)]	Gathering & Processing	2	173	9	62,262	1	1,110
Southwest Wyoming	Rendezvous [(4)]	Gathering	—	—	1	7,485	1	338
Total			8	1,480	32	173,488	6	4,405

(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 Patrick Draw cryogenic processing plant and the Red Desert 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. Anadarko provided 67% of the throughput at the Bison treating facility for the year ended December 31, 2014. The remaining throughput was from one third-party producer.

- 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 pipeline, operated by TransCanada Corporation, is connected directly to the facility, which is currently the only inlet into the pipeline. The Bison treating facility also has access to Fort Union's pipeline and Meritage Midstream Services II, LLC's Thunder Creek pipeline.

Fort Union gathering system and treating facility

- Customers. Anadarko and the other members of Fort Union (Copano Pipelines/Rocky Mountains, LLC, Crestone Powder River LLC, and Bargath, LLC) are the only firm shippers on the Fort Union system. To the extent capacity on the system is not used by the members, it is available to third parties under interruptible agreements.

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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 throughout the Powder River Basin. As of December 31, 2014, the Fort Union system gathered gas from 1,900 Anadarko-operated coal-bed methane wells producing in the Big George coal play and a nearby multi-seam coal fairway. Anadarko had a working interest in over 1.1 million gross acres within the Powder River Basin as of December 31, 2014. Another of the Fort Union owners has a comparable working interest in a large majority of Anadarko's producing coal-bed methane wells. The two remaining Fort Union owners 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 primarily from numerous third-party customers, with the six largest producers providing 71% of the system throughput during the year ended December 31, 2014.

- Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse Counties. Our customers, including Anadarko, have historically maintained and more recently increased throughput by developing new prospects and performing workovers.

- 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 its 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 80% of the system throughput during the year ended December 31, 2014. The largest producer provided 57% of the throughput during the year ended December 31, 2014.

- 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 MGTC, Inc. (“MGTC”) intrastate pipeline, a Hinshaw pipeline that supplies local markets in Wyoming, for transport, distribution and sale.

Southwest Wyoming

Granger gathering system and processing complex

- Customers. For the year ended December 31, 2014, 7% of the Granger complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the five largest shippers providing 86% of the system throughput.

- Supply. The Granger complex is supplied by the Moxa Arch and the Jonah and Pinedale anticline fields. The Granger gas gathering system had 667 active receipt points as of December 31, 2014.

- 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”) and our Mountain Gas Transportation, Inc.’s (“MGTI”) pipeline via a connect with Tesoro Logistics LP’s (“Tesoro”) Rendezvous pipeline (“Rendezvous pipeline”);
The Williams Companies, Inc.’s Northwest pipeline (“NWPL”); and
our Overland Trail Transmission, LLC’s pipeline (“OTTCO”).

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, 2014, 4% of the Red Desert complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the six largest producers providing 70% of the system throughput.

- Supply. The Red Desert complex gathers, compresses, treats and processes natural gas and fractionates NGLs produced in 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 shippers on the Rendezvous gathering system. To the extent capacity on the system is not used by those shippers, it is available to third parties under interruptible agreements.

- Supply and delivery points. The Rendezvous gathering system provides mainline 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 Questar Pipeline Company's pipeline ("Questar pipeline"), NWPL and the Kern River pipeline via the Rendezvous pipeline.

Overview - Rocky Mountains - Colorado and Utah

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Location	Asset	Type	Processing / Treating Plants	Processing / Treating Capacity (MMcf/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Colorado	DJ Basin complex (1)	Gathering, Processing & Treating	6	619	21	196,928	2	3,213
Utah	Chipeta (2)	Processing	2	970	—	91,307	—	—
Utah	Clawson	Gathering & Treating	1	40	1	6,310	1	47
Utah	Helper	Gathering & Treating	2	52	2	14,075	1	67
Total			11	1,681	24	308,620	4	3,327

(1) The DJ Basin complex includes the Platte Valley cryogenic processing plant, the Wattenberg gathering system, the Fort Lupton processing plant, the Fort Lupton JT processing plant, the Hambert JT processing plant, the Platteville amine treating plant and the Lancaster plant. Train II of the Lancaster plant is currently under construction and is expected to be completed during the second quarter of 2015.

(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.

Rocky Mountains - Colorado

DJ Basin gathering system, treating facility and processing complex

- Customers. For the year ended December 31, 2014, 68% of the DJ Basin complex throughput was from Anadarko and the remaining throughput was from various third-party customers, with the largest providing 21% of the throughput.

- Supply and delivery points. There were 2,881 active receipt points connected to the DJ Basin complex as of December 31, 2014. The DJ Basin complex is primarily supplied by the Wattenberg field, in which Anadarko controls 840,000 gross acres and drilled 369 wells and completed 330 wells during the year ended December 31, 2014.

As of December 31, 2014, the DJ Basin complex had the following delivery points for gas not processed within the DJ Basin complex:

Anadarko’s Wattenberg plant;
DCP Midstream’s (“DCP”) Spindle, Mewbourn and Platteville plants; and
AKA Energy Group, LLC’s Gilcrest plant.

The Anadarko Wattenberg plant and our DJ Basin complex are connected to CIG and Xcel Energy’s residue pipelines. The DJ Basin complex is also connected to the Overland Pass Pipeline Company LLC’s pipeline, DCP’s Wattenberg pipeline and FRP’s pipeline for NGLs. In addition, a 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 on the Chipeta system with 82% of the system throughput for the year ended December 31, 2014. The balance of throughput on the system during the year ended December 31, 2014 was from nine third-party customers.

- Supply. The Chipeta system is well positioned to access Anadarko and third-party production in the Uinta Basin where Anadarko controls 245,000 gross acres. Chipeta's inlet is connected to Anadarko's Natural Buttes gathering system, the Questar pipeline and the 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 natural gas delivery points through the following pipelines:

CIG;
Questar pipeline; and
WIC.

Clawson gathering system and treating facility

- Customers. Anadarko is the largest shipper on the Clawson gathering system with 99% of the total throughput on the system during the year ended December 31, 2014. The remaining throughput on the system was from one third-party producer.

- Supply. The Clawson Springs field covers 7,000 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 each of the Helper and Cardinal Draw fields.

- Delivery points. The Helper gathering system delivers into the Questar pipeline.

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Overview - Mid-Continent and North-central Pennsylvania

Location	Asset	Type	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
Southwest Kansas & Oklahoma	Hugoton	Gathering	42	90,214	1	2,067
North-central Pennsylvania	Non-Operated Marcellus [(1)]	Gathering	4	70,750	2	481
North-central Pennsylvania	Anadarko-Operated Marcellus [(2)]	Gathering	—	—	3	151
Total			46	160,964	6	2,699

(1) We own a 33.75% interest (the “Non-Operated Marcellus Interest”) in the Liberty and Rome gas gathering systems (the “Non-Operated Marcellus Interest gathering systems”), with a third party as the operator.

(2) We own a 33.75% interest (the “Anadarko-Operated Marcellus Interest”) in the Larry’s Creek, Seely and Warrensville gas gathering systems (the “Anadarko-Operated Marcellus Interest gathering systems”), with Anadarko as the operator.

Southwest Kansas and Oklahoma

Hugoton gathering system

- Customers. Anadarko is the largest customer on the Hugoton gathering system with 86% of the system throughput during the year ended December 31, 2014. Two third-party shippers account for 8% of the system throughput, with the balance from various other third-party shippers.

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- Supply. The Hugoton field continues to be a long-life, low-decline asset for Anadarko, which has an extensive acreage position in the field with 470,000 gross acres. The Hugoton system is well positioned to gather volumes that may be produced from successful new wells drilled by third-party producers.

- Delivery points. The Hugoton gathering system is connected to the Satanta plant, which is owned by Anadarko (49%) and a third party. The Satanta plant processes NGLs and helium, and delivers residue into the Kansas Gas Service's pipeline and Southern Star Central Gas Pipeline, Inc.'s pipeline. The system is also connected to DCP's National Helium Plant, which extracts NGLs and delivers residue into Energy Transfer Partners, LP's ("ETP") Panhandle Eastern Pipe Line.

North-central Pennsylvania

Marcellus gathering systems

- Customers. As of December 31, 2014, there were seven and five priority shippers on the Non-Operated Marcellus Interest gathering systems and the Anadarko-Operated Marcellus Interest gathering systems, respectively, including Anadarko. For the year ended December 31, 2014, Anadarko represented 21% and 36% 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, 2014, Anadarko had a working interest in over 722,000 gross acres within the Marcellus shale. 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 Capacity (MBbls/d)	Compressor Stations	Compression Horsepower	Gathering Systems	Pipeline Miles
East Texas	Dew	Gathering	—	—	—	9	36,085	1	324
East Texas	Pinnacle [1]	Gathering & Treating	1	500	—	1	1,340	1	270
East Texas	Mont Belvieu JV [2]	Processing	2	—	170	—	—	—	—
South Texas	Brasada complex [3]	Gathering, Processing & Treating	2	200	—	—	—	1	71
West Texas	Haley	Gathering	—	—	—	—	—	1	142
West Texas	DBM complex [4]	Gathering, Processing & Treating	3	300	—	4	23,575	1	253
Total			8	1,000	170	14	61,000	5	1,060

(1) The Pinnacle system includes the Bethel treating facility.
(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) The table above excludes 15MBbls/d of condensate stabilization capacity at the Brasada complex.
(4) The table above excludes 1,800 gpm of amine treating capacity at the DBM complex.

East and South Texas

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East Texas

Dew gathering system

- Customers. Anadarko is the largest shipper on the Dew gathering system with 99% of the total throughput on the system during the year ended December 31, 2014. The remaining throughput on the system was from two third-party producers.
- Supply. As of December 31, 2014, Anadarko had 794 producing wells in the Bossier play and controlled 111,000 gross acres in the area.
- Delivery points. The Dew gathering system has delivery points on Kinder Morgan, Inc.’s Tejas pipeline (“Tejas pipeline”) and with Pinnacle, which is the primary delivery point and is described in more detail below.

Pinnacle gathering system and treating facility

- Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 92% of system throughput for the year ended December 31, 2014. The remaining throughput on the system during that period was from five third-party shippers.
- Supply. The Pinnacle gathering system is well positioned to provide sour gas gathering and treating services to the five-county area over which it extends, including the Cotton Valley Lime and Reef formations, which contain relatively high concentrations of hydrogen sulfide and carbon dioxide.
- Delivery points. The Pinnacle gathering system is connected to the following pipelines:

Atmos Energy’s Texas pipeline;
Midcoast Energy Partners, LP’s East Texas system;
Energy Transfer Fuels’ pipeline;
Enterprise Texas Pipeline, LP’s pipeline;
ETC Texas Pipeline, Ltd’s pipeline; and
the Tejas pipeline.

These pipelines provide transportation to the Carthage, Waha and Houston Ship Channel market hubs in Texas.

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 and TEP. Individual NGLs are delivered to end users either through customer-owned pipelines that are connected to nearby petrochemical plants or via export terminal.

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South Texas

Brasada gathering system, stabilization facility and processing complex

- Customers. Anadarko provides 100% of the throughput to the Brasada complex. Anadarko delivers gas and condensate to the plant on behalf of itself and its upstream partners.

- Supply. Supply of gas and NGLs for the facility comes from Anadarko's production in the Eagleford shale, in which Anadarko controls 416,000 gross acres.

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

West Texas

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Haley gathering system

- Customers. Anadarko’s production represented 68% of the Haley gathering system’s throughput for the year ended December 31, 2014. The remaining throughput was attributable to one third-party producer.

- Supply. As of December 31, 2014, Anadarko had access to 445,000 gross acres in the greater Delaware Basin, a portion of which is gathered by the Haley gathering system.

- Delivery points. The Haley gathering system has multiple delivery points. The primary delivery points are to Kinder Morgan, Inc.’s El Paso Natural Gas pipeline (“El Paso pipeline”) or Enterprise GC, LLC’s pipeline for ultimate delivery into ETP’s Oasis pipeline (“Oasis pipeline”). We also have the ability to deliver into Southern Union Energy Services’ pipeline for further delivery into the Oasis pipeline. The pipelines at these delivery points provide transportation to both the Waha and Houston Ship Channel markets.

DBM gathering system, treating facility and processing complex. The DBM complex includes 300 MMcf/d of cryogenic processing capacity, 1,800 gpm of amine treating capacity and a 253-mile rich gas gathering system, which has both high and low pressure segments.

- Customers. Gas gathered and processed through the DBM complex is primarily from nine third party producers, with the three largest producers providing 77% of the system throughput for the year ended December 31, 2014.

- Supply. Supply of gas and NGLs for the complex comes from production from the Delaware Sands, Avalon Shale, Bone Springs and Wolfcamp formations in the Delaware Basin portion of the Permian Basin. Anadarko currently holds 445,000 gross acres within the Delaware Basin.

- Delivery points. Residue gas produced at the facility is delivered to an interconnect with the El Paso pipeline. NGL production is delivered to an interconnect with DCP’s Sand Hills pipeline. As of December 31, 2014, there was an additional NGL interconnect under construction at our DBM complex with an expected in-service date during the first quarter of 2015.

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TRANSPORTATION

Overview

Location	Asset	Type	Compressor Stations	Operational Horsepower	Pipeline Miles
Northeast Wyoming	MIGC (1)	Gas	10	24,828	262
Southwest Wyoming	OTTCO	Gas	1	3,174	217
Utah	GNB NGL (1)	NGL	—	—	32
Colorado, Kansas, Oklahoma	White Cliffs (1) (2)	Oil	—	—	526
Colorado, Oklahoma, Texas	FRP (1) (3)	NGL	1	7,500	435
Texas, Oklahoma	TEG	NGL	6	1,895	117
Texas	TEP (1) (3)	NGL	1	25,000	593
Total			19	62,397	2,182

(1) MIGC, GNB NGL, White Cliffs, FRP and TEP are regulated by the Federal Energy Regulatory Commission (“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 87% of throughput for the year ended December 31, 2014. The remaining throughput on the MIGC system was from 17 third-party shippers. MIGC offers both forward-haul and backhaul transportation services and is certificated for 175 MMcf/d of firm transportation capacity.

- Supply. As of December 31, 2014, Anadarko had a working interest in over 1.1 million gross acres within the Powder River Basin. Anadarko’s gross acreage includes substantial undeveloped acreage positions in the Big George coal play and the multiple seam coal fairway to the north of the Big George coal play. MIGC receives gas from various coal-bed methane gathering systems throughout 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 MGTC.

Rocky Mountains - Southwest Wyoming

OTTCO transportation system

- Customers. For the year ended December 31, 2014, 12% 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. Most of OTTCO's gas transportation agreements are month-to-month with the remainder generally having terms of less than one year. OTTCO has one current third-party firm transportation agreement for 21 MMBtu/d, which extends through December 2021.

Supply and delivery points. Supply points to the OTTCO transportation system include 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 interconnection with 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, 2014.
- 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, 2014. 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 over 200 MBbls/d. These expansion projects are scheduled to be completed in mid-to-late 2015.
- Supply. The White Cliffs pipeline is supplied by production from the DJ Basin and offers the only direct route from the DJ Basin to Cushing, Oklahoma.
- 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 300,000-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 injection points from gas plants in Weld County, Colorado (including our Lancaster plant), which is part of 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, 2014, FRP had two 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, 2014.
- 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, 2014 and provides capacity for other shippers at the posted FERC tariff rates.

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Assets Under Development

We currently have the following significant projects scheduled for completion in 2015 and 2016.

- Lancaster Train II in the DJ Basin: We are currently constructing the second train of the Lancaster plant, which is part of the DJ Basin complex. The second train is designed to have a capacity of 300 MMcf/d and is expected to begin service during the second quarter of 2015. Anadarko has agreed to a fee-based contract with a 10-year throughput guarantee of 200 MMcf/d, which will begin on the plant's in-service date.

- DBM Trains IV and V in West Texas: We are currently preparing for the construction of an additional cryogenic unit at our DBM complex with 200 MMcf/d of designed processing capacity and an in-service date expected during the first quarter of 2016. We have also made progress payments towards the construction of another cryogenic unit at our DBM complex (Train V), with an expected in-service date of mid-2016.

COMPETITION

The midstream services business is very competitive. Our competitors include other midstream companies, producers, and intrastate and interstate pipelines. Competition for natural gas and NGL volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies. However, a substantial portion of our 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, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton 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, 2014.

System	Competitor(s)
Anadarko-Operated Marcellus Interest gathering systems	Regency Energy Partners LP (formerly PVR Midstream) and National Fuel Gas Midstream Corporation
Bison treating facility	Thunder Creek Gas Services, LLC and Fort Union (treating only)
Brasada gathering system, stabilization facility and processing complex	Enterprise, ETP and Kinder Morgan, Inc.
Chipeta processing complex	Tesoro and Kinder Morgan, Inc.
Dew and Pinnacle gathering systems and Pinnacle treating facility	ETC Texas Pipeline, Ltd., Midcoast Energy Partners, LP (East Texas), XTO Energy and the Tejas pipeline
DJ Basin gathering system, treating facility and processing complex	DCP and AKA Energy Group, LLC
Fort Union gathering system and treating facility	Bison treating facility (carbon dioxide treating services only), MIGC, Thunder Creek Gas Services, LLC and TransCanada Corporation
Granger gathering system and processing complex	Williams Field Services, Enterprise/Jonah Gas Gathering Company and Tesoro
Haley gathering system	Anadarko's Delaware Basin Joint Venture, Enterprise GC, LP, Regency Gas Services, LP and Targa Midstream Services, LP
Helper and Clawson gathering systems and treating facilities	XTO Energy
Hilight gathering system and processing plant	DCP, ONEOK Gas Gathering Company, Thunder Creek Gas Services, LLC, Crestwood-Access, Tallgrass Energy Partners, LP and Rowdy Gathering Company
Hugoton gathering system	ONEOK Gas Gathering Company, DCP and Linn Energy
Mont Belvieu JV fractionation trains	Targa Resources LP, Phillips 66, Lone Star NGL LLC and ONEOK Partners, LP
Newcastle gathering system and processing plant	DCP
Non-Operated Marcellus Interest gathering systems	Regency Energy Partners, LP (formerly PVR Midstream)
DBM gathering system, treating facility and processing complex	Anadarko's Delaware Basin Joint Venture, Regency Gas Services, Enterprise GC, LP and Targa Midstream, LP
Red Desert gathering system and processing complex	Williams Field Services and Tesoro
Rendezvous gathering system	No significant direct competition

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, which commenced operations in January 2011, and the Fort Union gathering system. The White Cliffs pipeline and the OTTCO transportation system face no direct competition from other pipelines, although White Cliffs pipeline shippers could sell crude oil in local markets or ship crude via rail services rather than via pipeline to Cushing, Oklahoma. The TEFR interests compete with DCP’s Sand Hills pipeline, West Texas LPG Pipeline LP’s pipeline and the Seminole pipeline.

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REGULATION OF OPERATIONS

Safety and Maintenance

Many of the pipelines we use to gather and transport natural gas and NGLs are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the Department of Transportation (the “DOT”) 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. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (the “PSI Act”) and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the “PIPES Act”). Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline wall thicknesses, design pressures, maximum operating pressures, 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,” where a release could have the most significant adverse consequences, including high population areas, certain drinking water sources and unusually sensitive ecological areas. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; 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.
These pipeline safety laws were amended in January 2012, when President Obama signed the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the “2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directed the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, pipeline material strength testing, verification of the maximum allowable pressure of certain pipelines, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmissions pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and from $1.0 million to $2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any of which could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

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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. We do not anticipate any significant difficulty or material cost in complying with applicable intrastate pipeline safety laws and regulations in 2015. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements. We, or the entities in which we own an interest, inspect our pipelines regularly in substantial compliance with applicable state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states in which we operate that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in response to an August 2014 report from the U.S. Government Accountability Office (the "GAO"), PHMSA stated that it is developing revisions to its pipeline safety regulations, including consideration of the need to adopt safety requirements for gas gathering pipelines that are not currently subject to regulation.

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. The OSHA hazard communication standard, the community right-to-know regulations of the U.S. Environmental Protection Agency (the "EPA") under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes 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. We and the entities in which we own an interest are also subject to OSHA's Process Safety Management ("PSM") regulations as well as EPA's Risk Management Program ("RMP") regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds or any process which involves flammable liquid or gas in excess of 10,000 pounds. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety. However, notwithstanding the applicability of these PSM and RMP requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in the past expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid pipeline safety requirements. These actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current PSM and RMP 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.

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 operation of our MIGC pipeline and the natural gas residue pipeline at the tailgate of the DBM complex (the "DBM pipeline") 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;

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- 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.

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. 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, the rates and revenues for our FERC-regulated pipelines could be adversely affected.

Interstate natural gas pipelines regulated by FERC are 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 promulgated pursuant to the Energy Policy Act of 2005 (the "EPAct 2005") 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 (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 (the "NGPA") to give FERC authority to impose civil penalties for violations of these statutes, up to $1.0 million per day per violation for violations occurring after August 8, 2005. Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

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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 NGL pipelines with FERC tariffs on file provide service as common carriers 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.

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. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, 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 DBM pipeline. 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. 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. 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.

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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 new 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. As noted above, FERC's civil penalty authority under EPAct 2005 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 shippers 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. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of the products that we produce, as well as the revenues we receive for sales of such products.

In the event any of our intrastate pipelines offer natural gas transportation services under Section 311 of the NGPA, 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 under EPAct 2005 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, please read Risk Factors under Item 1A of this Form 10-K for more information.

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ENVIRONMENTAL MATTERS

General

Our operations are subject to stringent federal, tribal, state and local laws and regulations relating to the protection of the environment. These laws and regulations can restrict or impact our business activities in many ways, such as requiring the acquisition of permits to conduct regulated activities; restricting the way we emit, discharge or dispose of our wastes; limiting or prohibiting construction activities in sensitive areas, such as wetlands and other protected areas; requiring remedial actions to mitigate pollution from former and current operations; and imposing substantial liabilities for pollution resulting from our operations. Failure to comply with these requirements may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining performance of some or all of our operations. Also, certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hydrocarbons or wastes have been disposed or released. Our operations and construction activities are also subject to state and local ordinances that require us to take curative actions to reduce or mitigate nuisance-type conditions such as excessive levels of dust or noise or increased traffic congestion.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in substantial compliance with environmental laws and regulations. The trend in environmental regulation is to place more restrictions on activities that may affect the environment, and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be significantly in excess of the amounts we currently anticipate. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with existing requirements will not materially affect us, there is no assurance that the current conditions will continue in the future or that such future compliance will not have a material adverse effect on our business, financial conditions or results of operations.

Below is a discussion of several of the material environmental laws and regulations, as amended from time to time, that relate to our business.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include current and prior owners or operators of the site where a release of hazardous substances occurred and companies that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these “responsible persons” may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. We generate materials in the course of our ordinary operations that are regulated as “hazardous substances” under CERCLA or similar state laws.

We also generate non-hazardous and hazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act (the “RCRA”) and comparable state statutes. While the RCRA regulates both non-hazardous and hazardous wastes, it imposes more stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the ordinary course of our operations and our customer’s operations, wastes are generated constituting non-hazardous waste and, in some instances, hazardous wastes.

We own or lease properties where petroleum hydrocarbons are being or have been handled for many years. We have generally used operating and disposal practices that were standard in the industry at the time, although petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us, or on or under the other locations where these petroleum hydrocarbons and wastes have been transported for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws.

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Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining permits and approvals for air emissions. For example, in December 2014, the EPA published proposed regulations to revise the National Ambient Air Quality Standard (the “NAAQS”) for ozone, recommending a standard between 65 to 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards, protective of public health and public welfare, respectively. The current primary and secondary ozone standards are each set at 75 ppb. In June 2014, the Clear Air Scientific Advisory Committee concluded that scientific evidence supported a standard between 60 to 70 ppb. Ultimately, the EPA decided to propose a new standard between 65 and 70 ppb, but is taking comment on whether a 60 ppb standard should be established for the primary standard or whether the existing 75 ppb standard should be retained. Compliance with existing and potential regulatory requirements, such as the proposed lowering of the ozone standard, may require modifications to certain operations, including the installation of new emission controls on our surface equipment that could result in longer permitting timelines, as well as a significantly increase in our operational costs, including increased capital expenditures and operation costs, which could adversely impact our business. The EPA expects to issue a final rule by October 1, 2015.

Climate Change

The EPA has adopted regulations under the Clean Air Act that, among other things, establish construction and operating permit reviews for greenhouse gas (“GHG”) emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain operating permits for their GHG emissions are required to meet best available control technology standards that typically are established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States including, among others, onshore processing, transmission, storage and distribution facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring GHG emissions from our facilities in accordance with current GHG emissions reporting requirements in a manner that we believe is in substantial compliance with applicable reporting obligations and are currently assessing the potential impact that the December 9, 2014 proposed rule may have on our future reporting obligations, should the proposal be adopted.

In January 2015, the Obama Administration announced plans to reduce GHGs by regulating methane emissions from the oil and natural gas sector. The Obama Administration stated that they will seek to reduce methane emissions in the oil and natural gas sector by 40 to 45 percent from 2012 levels by 2025. There are a number of elements involved in the plan, including efforts by the EPA, the DOT and the Department of the Interior. As to the EPA, the Obama Administration announced that the EPA will propose new source rules for methane this summer and seek to finalize them in 2016.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulation that requires reporting of GHGs or otherwise restricts emissions of GHGs from our or our customers’ equipment and operations could require us or our customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for our services.

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Water Discharges

The federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants or dredged and fill material into state waters, as well as waters of the United States and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance.
The federal Oil Pollution Act of 1990 (the “OPA”) which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under the OPA includes, among others, owners and operators of onshore facilities, such as our plants and pipelines.

Hydraulic Fracturing

Although we do not directly engage in hydraulic fracturing, our customers do conduct such activities. Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or oil from low permeability hydrocarbon bearing subsurface rock formations. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies but several federal agencies have asserted regulatory authority over aspects of the process, including the EPA and the federal Bureau of Land Management (“BLM”). From time to time, the U.S. Congress has considered legislation to provide for federal regulation of hydraulic fracturing, but in the absence of any laws adopted by Congress, a growing number of states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. In addition, in December 2014, the state of New York prohibited hydraulic fracturing altogether. Also, 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, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA, which is planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. The results of such review or studies could spur initiatives to further regulate hydraulic fracturing. The adoption of new laws or regulations at the federal, state or local levels imposing more stringent restrictions on hydraulic fracturing could make it more difficult for our customers to complete wells, increase our customers’ costs of compliance and doing business, and otherwise adversely affect the hydraulic fracturing services they perform, which could negatively impact demand for our gathering and processing services.

Endangered Species Considerations

The Endangered Species Act (the “ESA”) restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered for migratory birds under the Migratory Bird Treaty Act. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to review and consider the listing of numerous species as endangered under the ESA by no later than the completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers’ performance of operations, which could reduce demand for our midstream services.

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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 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 are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. 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

We do not have any employees. The officers of our general partner manage our operations and activities under the direction and supervision of our general partner’s Board of Directors. As of December 31, 2014, Anadarko employed 360 people who provided direct support to our field operations. All of the employees required to conduct and support our operations are employed by Anadarko and are covered either under a services and secondment or omnibus 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.

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Item 1A. Risk Factors

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

- our ability to pay distributions to our unitholders;
- our and Anadarko’s assumptions about the energy market;
- future throughput, including Anadarko’s production, which is gathered or processed by or transported through our assets;
- our operating results;
- competitive conditions;
- technology;
- the availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;
- the supply of, demand for, and the price of, oil, natural gas, NGLs and related products or services;
- weather and natural disasters;
- inflation;
- the availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;
- federal, state and local laws, including those that limit Anadarko 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;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- our ability to use our RCF;
- the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners and other parties;
- our ability to repay debt;
- our ability to mitigate a substantial majority of the commodity price risks inherent in our percent-of-proceeds and keep-whole contracts;
- conflicts of interest among us, our general partner, WGP and its general partner, and affiliates, including Anadarko;
- our ability to maintain and/or obtain rights to operate our assets on land owned by third parties;
- our ability to acquire assets on acceptable terms;
- non-payment or non-performance of Anadarko or other significant customers, including under our gathering, processing and transportation agreements and our $260.0 million note receivable from Anadarko;
- the timing, amount and terms of future issuances of equity and debt securities; and
- other factors discussed below and elsewhere in this Item 1A, under the caption Critical Accounting Policies and Estimates included under 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 report could cause actual results to differ materially from those contained in any forward-looking statement. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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 majority of the natural gas that we gather, treat, process and 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 majority of the natural gas that we gather, treat, process and transport. For the year ended December 31, 2014, 48% of our total gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) was comprised of natural gas production owned or controlled by Anadarko. For the year ended December 31, 2014, 57% of our total processing throughput (excluding equity investment throughput and throughput measured in barrels) was attributable to natural gas production owned or controlled by Anadarko. Anadarko may suffer a decrease in production volumes 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 reduce its drilling activity in our areas of operation or determine that drilling activity in other areas of operation is strategically more attractive. 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 ultimate owner 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 ultimate parent 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 natural gas and oil prices, which could have a negative effect on the value of Anadarko's oil and natural gas properties, its drilling programs or its ability to finance its operations;
- the availability of capital on an economic basis 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 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; 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, 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. Further, unless and until we receive full repayment of the $260.0 million note receivable from Anadarko, we will be subject to the risk of non-payment or late payment of the interest payments and principal of the note. 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.

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 under 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.

Please see Item 1A in Anadarko's Form 10-K for the year ended December 31, 2014 (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.

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

Sustained low natural gas, NGL or crude 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 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 has contributed significantly to a substantial drop in crude oil prices. For example, daily settlement prices for New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude oil ranged from a high of $107.26 per barrel to a low of $53.27 per barrel during 2014. Daily settlement prices for NYMEX Henry Hub natural gas ranged from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu during 2014. 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 ("LNG");

- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials, such as in the Mid-Continent or 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, natural gas, NGLs and other commodities.

Because of the natural decline in production from existing wells, our success depends on our ability to obtain new sources of natural gas, which is dependent on certain factors beyond our control. Any decrease in the volumes of natural gas 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 wells connected to our gathering systems and processing and treatment 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 natural gas. The primary factors affecting our ability to obtain sources of 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 natural gas reserves. Declines in natural gas prices have had a negative impact on natural gas exploration, development and production activity and, if sustained, could lead to a material 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 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.

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 2014 distribution of $0.70 per unit per quarter, or $2.80 per unit per year, we will require available cash of $126.0 million per quarter, or $504.2 million per year, based on the number of common units, general partner units and IDRs outstanding at February 2, 2015. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the announced distribution. 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 natural gas;

• the volume of natural gas we gather, compress, process, treat and 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 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.

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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; and
- the amount of cash reserves established by our general partner.

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, 2014, 20% of our 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, condensate 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 at various times through December 2016 to manage a substantial 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.

On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. 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 may be 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.

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Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, operating restrictions or delays in the completion of oil and 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. The U.S. Congress has, from time to time, considered legislation to provide for federal regulation of hydraulic fracturing, but while the Congress has not adopted any such laws in recent years, several federal agencies, including the EPA and the BLM, have asserted regulatory authority over aspects of the process. In addition, a growing number of states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations. Moreover, more stringent regulation of hydraulic fracturing may occur at the local level, resulting in the need to comply with local measures in addition to regulations typically imposed by state oil and gas commissions and similar agencies. If state or local restrictions or prohibitions are adopted in our areas of operations, such as in the Wattenberg field, our customers, including Anadarko, may incur significant compliance costs or may experience delays or curtailment in the pursuit of their exploration, development, or production activities, and possibly be limited or precluded in the drilling of certain wells altogether. Any adverse impact on our customers' activities would have a corresponding negative impact on our throughput volumes. Accordingly, such restrictions or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, cash flows, and ability to make distributions to our unitholders. 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.
For example, in exchange for the withdrawal of several initiatives relating to hydraulic fracturing and other oil and gas operations proposed for inclusion on the Colorado state ballot in November 2014, the governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations in September 2014 to make recommendations to the state legislature regarding the responsible development of Colorado's oil and gas resources. Although it is early in the process, it is possible that, as a result of the task force's recommendations, Colorado could adopt new policies or legislation relating to oil and natural-gas operations, including measures that would give local governments in Colorado greater authority to limit hydraulic fracturing and other oil and natural-gas operations or require greater distances between well sites and occupied structures. Moreover, states could elect to prohibit hydraulic fracturing altogether, as the state of New York did in December 2014.
In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA, with the EPA planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. The results of these existing or any future reviews and studies could spur initiatives to further regulate hydraulic fracturing.

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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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 oil and natural gas exploration and production. 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.

Restrictions in the indentures governing our 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes" and together with the 2021 Notes, the 2022 Notes, and the 2018 Notes "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 indentures governing the Notes and in the RCF and any future financing agreements 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 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. See Item 7 of this Form 10-K for a further discussion of the terms of our RCF and Notes.

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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.

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.

A downgrade or other negative credit-rating action with respect to our or Anadarko’s credit rating could negatively impact our cost of, and ability to access, capital.

We cannot provide assurance that our credit ratings or those of Anadarko will not be downgraded, or that other adverse credit-rating events will not occur. A downgrade or notice of potential downgrade of either our or Anadarko’s credit ratings could negatively impact our ability to access the capital markets, increase our borrowing costs, or limit our ability to effectively execute aspects of our strategy.

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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, either because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms or (iii) outbid by competitors, 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.

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, 2014, on all of our common units, general partner units and IDRs was $126.0 million, or $504.2 million per year. The Class C unit distribution, if paid in cash, would have been $3.1 million for the quarter ended December 31, 2014.

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

We typically do not obtain independent evaluations of natural gas 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 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 natural gas and NGL prices continue to 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 substantially all 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.
Further, at December 31, 2014, we had $384.4 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.
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 that could have a substantial negative effect on our profitability, such as if we are unable to maintain the throughput on our asset base or if other adverse events, such as sustained lower oil and natural gas prices, reduce the fair value of the associated reporting unit. Future non-cash asset impairments could negatively affect our results of operations.

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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 natural gas 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 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 under the NGA and the EPAct 2005. If we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority to impose penalties for current violations of the NGA or NGPA 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 the NGA and EPAct 2005.
Our interstate liquids pipelines are common carriers and are subject to regulation by FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders.
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.

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.

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Climate change legislation or regulatory initiatives could increase our operating and capital costs and could decrease demand for our midstream services.

The EPA has adopted regulations under the Clean Air Act that establish construction and operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Facilities subject to these permitting requirements for their GHG emissions also will be required to meet BACT standards that typically are established by the states. Compliance with these permitting programs could restrict or delay our ability to obtain air permits for new or modified sources. The EPA has also adopted rules establishing a reporting program requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States including, among others, onshore processing, transmission, storage and distribution facilities. In January 2015, the Obama Administration announced plans to reduce GHGs by regulating methane emissions from the oil and natural gas sector. The Obama Administration stated that they will seek to reduce methane emissions in the oil and natural gas sector by 40 to 45 percent from 2012 levels by 2025. There are a number of elements involved in the plan, including efforts by the EPA, DOT and Department of the Interior. As to the EPA, the Obama Administration announced that the EPA will propose new source rules for methane this summer and seek to finalize them in 2016.

Congress has from time to time considered legislation to reduce emissions of GHGs, and a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emissions allowances in return for emitting those GHGs. The increased costs of operations or delays in drilling that could be associated with climate change legislation may reduce drilling activity by Anadarko or third-party producers in our areas of operation, with the effect of reducing the throughput available to our systems. Further, the adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the natural gas and NGLs we gather and process. Such developments could materially adversely affect our financial position, results of operations and cash available for distribution to our unitholders.

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 Dodd-Frank Act requires the Commodity Futures Trading Commission (the “CFTC”), the SEC and other federal regulators to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has finalized the majority of its regulations, but others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished or what the terms of the final rules will be.

In its rulemaking under the Dodd-Frank Act, the CFTC has proposed regulations to set position limits for certain futures contracts in designated physical commodities including, among others, oil and natural gas, and for options and swaps that are their economic equivalent. Certain bona fide hedging positions would be exempt from these position limits under the regulations as currently proposed. It is not possible at this time to predict when the CFTC will finalize these regulations or whether the proposed rules will be modified prior to becoming effective, so the impact of those provisions on us is uncertain at this time.

As part of the Dodd-Frank reforms, the CFTC has designated certain types of swaps (thus far, 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.

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The Dodd-Frank Act requires that regulators establish margin rules applicable to uncleared swaps. However, a recent amendment to the act and the CFTC's proposed margin rule exempt from the margin requirements certain uncleared swaps with end users. It is not possible at this time to predict whether the proposed rule will be modified to impose any limitations on the exemption. To the extent that any final margin rules limit the exemption with respect to our swaps activity, 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. The financial reform legislation may also require some counterparties to spin off some of their derivative activities to separate entities that may not be as creditworthy, thereby increasing the credit risk associated with our hedging activities. 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.
In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

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

Pursuant to authority under the NGPSA and the HLPSA, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, 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," 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 a high consequence area; (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 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 upgrades deemed necessary to ensure the safe and reliable operation of our pipelines.

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.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing, and verification of the maximum allowable pressure of certain pipelines. The 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from \$100,000 to \$200,000 per violation per day of violation and from \$1.0 million to \$2.0 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder 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 our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

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

Our operations are subject to stringent and complex 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 the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to limit or prevent releases of materials from our pipelines and facilities, and the 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 corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. There is an inherent risk of incurring significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several strict liabilities may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of substances or wastes on, under or from our properties and facilities, many of which have been used for midstream activities for many years, often by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our results of operations or financial condition.

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. Moreover, 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 Chipeta's limited liability company agreement, as amended and restated (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 members.

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, condensate 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 of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;

- leaks of natural gas containing hazardous quantities of hydrogen sulfide from our Pinnacle gathering system or Bethel treating facility;

- fires and explosions; and
- 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. For example, we do not have any property insurance on our underground pipeline systems that would cover damage to the pipelines. 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.

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 is 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 general partner's 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 88.3% 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.

- 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.

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Our partnership agreement permits us to classify up to $31.8 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the IDRs.

- 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.

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- Our general partner intends to limit its liability regarding our contractual and other obligations.
- 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 of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Please read Item 13 of this Form 10-K.

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, a majority 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.

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. The reimbursements to Anadarko and our general partner reduce the amount of cash otherwise available for distribution to our unitholders.

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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.

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 in 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;

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- 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;
- 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 of our general partner, 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 of our general partner 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.

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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.

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 of our general partner 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 and Class C units) voting together as a single class is required to remove our general partner. As of February 23, 2015, WGP owned a 34.9% limited partner interest in us. Other subsidiaries of Anadarko separately owned an aggregate 8.3% 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 and persons who acquired such units with the prior approval of the Board of Directors of our general partner, 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 its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets 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. The 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.

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 23, 2015, WGP held 49,296,205 common units and other subsidiaries of Anadarko held 757,619 common units and 10,959,564 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.

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 23, 2015, WGP owned a 34.9% limited partner interest in us, and other subsidiaries of Anadarko held an aggregate 8.3% limited partner interest in us, consisting of common and Class C units.

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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.
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 income tax on our taxable income at the corporate tax rate, 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.

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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 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. We have not requested, and do not plan to request, a ruling from the IRS on these or any other tax matters affecting our partnership tax treatment.

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.

At the state level, were we to be subject to federal income tax, we would also be subject to the income tax provisions of many states. Moreover, because of widespread state budget deficits and other reasons, several states are evaluating ways to independently subject partnerships to entity-level taxation through the imposition of state income taxes, franchise taxes and other forms of taxation. For example, we are required to pay Texas margin tax on our gross income apportioned to Texas. Imposition of any additional such taxes on us or an increase in the existing tax rates would reduce the cash available for distribution to our unitholders.

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.

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

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

Any modifications to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S.

federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our 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. For example, the IRS may reallocate items of income, deductions, credits or allowances between related parties if the IRS determines that such reallocation is necessary to clearly reflect the income of any such related parties. Such a reallocation may require us and our unitholders to file amended tax returns. Any contest by the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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 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. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax due with respect to that income.

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 the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation deductions and certain other items. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if a unitholder sells units, that unitholder may incur a tax liability in excess of the amount of cash received from the sale.

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 and 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. 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.

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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 have a negative impact on the value of our common units or result in audit adjustments to a unitholder’s tax returns.

We 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, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were to be issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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 loan of their common units should 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 being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the constructive 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. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. 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 interest in us (or a constructive termination of WGP) could, in conjunction with the trading of common units held by the public or other subsidiaries of Anadarko, result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could cause a 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 the unitholder's taxable income for the year of termination. A constructive termination would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

Except as discussed above, we are not a party to any legal, regulatory or administrative proceedings other than proceedings arising in the ordinary course of our business. Management believes that there are no such proceedings for which a final disposition could have a material adverse effect on our results of operations, cash flows or financial condition, or for which disclosure is otherwise required by Item 103 of Regulation S-K. We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please see Items 1 and 2 of this Form 10-K for more information.

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 New York Stock Exchange 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
2014				
High Price	$75.29	$79.81	$76.57	$66.50
Low Price	60.09	71.15	65.51	58.50
Distribution per common unit	0.700	0.675	0.650	0.625
2013				
High Price	$64.07	$65.16	$65.11	$59.81
Low Price	57.54	54.58	55.57	46.82
Distribution per common unit	0.600	0.580	0.560	0.540

As of February 23, 2015, there were 26 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 and 10,959,564 Class C units for which there is no established public trading market. All general partner units are held by our general partner and all Class C units are held by a subsidiary of Anadarko.

OTHER SECURITIES MATTERS

Unregistered sales of equity securities and use of proceeds. In connection with our November 2014 equity offering, our general partner purchased 153,061 general partner units for $10.8 million in cash. Proceeds from the November 2014 equity offering, including from the sale of the general partner units, were primarily used to fund the acquisition of DBM. The general partner units were issued in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended.

Securities authorized for issuance under equity compensation plans. In connection with the closing of our IPO, our general partner adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the “WES LTIP”), which permits the issuance of up to 2,250,000 units, of which 2,133,227 units remained available for future issuance as of December 31, 2014. Phantom unit grants under the WES LTIP have been made to each of the independent directors of our general partner and certain employees. Please read the information under Item 12 of this Form 10-K, which is incorporated by reference into this Item 5.

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Class C Unit Issuance. In connection with the closing of the DBM acquisition in November 2014, we issued 10,913,853 Class C units to APC Midstream Holdings, LLC ("AMH"), a subsidiary of Anadarko, at a price of $68.72 per unit, pursuant to the Unit Purchase Agreement ("UPA") with Anadarko and AMH. All outstanding Class C units will convert into common units on a one-for-one basis on December 31, 2017, unless we elect to convert such units earlier or Anadarko extends the conversion date. The distributions that Class C units receive are paid in the form of additional Class C units ("PIK C units") until the end of 2017 (unless earlier converted), and the Class C units are disregarded with respect to distributions of available cash until they are converted to common units. The terms of the Class C unit issuance were unanimously approved by the Board of Directors of our general partner and by the Board's Special Committee. On February 12, 2015, the Partnership's general partner distributed 45,711 PIK C units to the Class C unitholder. The 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.

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. The 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. It is intended that working capital borrowings 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, 2014, our general partner was entitled to 1.9% of all quarterly distributions that we make prior to our liquidation (see Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). Our general partner, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented.

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.300	98.1%	1.9%
First target distribution	up to $0.345	98.1%	1.9%
Second target distribution	above $0.345 up to $0.375	85.1%	14.9%
Third target distribution	above $0.375 up to $0.450	75.1%	24.9%
Thereafter	above $0.450	50.1%	49.9%

The maximum distribution sharing percentage of 49.9% includes distributions paid to our general partner on its 1.9% general partner interest and the 48.0% IDR maximum distribution sharing percentage, and 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

Unless the context otherwise requires, references to “we,” “us,” “our,” the “Partnership” or “Western Gas Partners” refer to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the “general partner” or “GP”), is owned by Western Gas Equity Partners, LP (“WGP”), a Delaware master limited partnership formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC is WGP’s general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. “Anadarko” refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and “affiliates” refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”), Enterprise EF78 LLC (the “Mont Belvieu JV”), Texas Express Pipeline LLC (“TEP”), Texas Express Gathering LLC (“TEG”) and Front Range Pipeline LLC (“FRP”). The interests in TEP, TEG and FRP are referred to collectively as the “TEFR Interests.” All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. “Equity investment throughput” refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput. The “DJ Basin complex” refers to the Platte Valley system, Wattenberg system and Lancaster plant, all of which were combined into a single complex in the first quarter 2014.
The term “Partnership assets” refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2014 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under 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 in the Notes to Consolidated Financial Statements under 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.

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Acquisitions

The following 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. In May 2008, concurrently with the closing of our initial public offering (“IPO”), Anadarko contributed to us the assets and liabilities of Anadarko Gathering Company LLC (“AGC”), Pinnacle Gas Treating LLC (“PGT”) and MIGC LLC (“MIGC”), which we refer to as our “initial assets.” In December 2008, we completed the acquisition of the Powder River assets from Anadarko, which included (i) the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% membership interest in Fort Union. In July 2009, we closed on the acquisition of a 51% membership interest in Chipeta Processing LLC (“Chipeta”) from Anadarko. We closed the acquisitions of Anadarko’s Granger and Wattenberg assets in January 2010 and August 2010, respectively. In September 2010, we acquired a 10% interest in White Cliffs, which consisted of a 9.6% third-party interest, and a 0.4% interest from Anadarko. In February 2011, we acquired the Platte Valley gathering system and processing plant from a third party, and in July 2011, we acquired the Bison gas treating facility from Anadarko. In January 2012, we acquired Mountain Gas Resources, LLC (“MGR”) from Anadarko, which acquisition included the Patrick Draw processing plant, the Red Desert processing plant, gathering lines, and related facilities (collectively, the “Red Desert complex”), and the 22% interest in Rendezvous, which are collectively referred to as the “MGR assets.” In August 2012, we acquired Anadarko’s then-remaining 24% membership interest in Chipeta (the “additional Chipeta interest”), receiving distributions related to the additional interest effective July 1, 2012. In March 2013, we completed the acquisition of a 33.75% interest (the “Non-Operated Marcellus Interest”) in both the Liberty and Rome gas gathering systems from a wholly owned subsidiary of Anadarko, Anadarko Marcellus Midstream, L.L.C. Also in March 2013, we completed the acquisition of a 33.75% interest (the “Anadarko-Operated Marcellus Interest”) in the Larry’s Creek, Seely and Warrensville gas gathering systems from a third party. In June 2013, we acquired a 25% interest in the Mont Belvieu JV from a third party, and in September 2013, we acquired Overland Trail Transmission, LLC, (“OTTCO”) from a third party. In March 2014, we acquired the TEFR Interests from Anadarko. In November 2014, we acquired Nuevo Midstream, LLC (“Nuevo”) from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC (“DBM”).

Dates of common control

In connection with its August 23, 2006, acquisition of Western Gas Resources, Inc., Anadarko acquired MIGC, the Powder River assets, the Granger assets and the MGR assets. Anadarko acquired the Wattenberg assets and a 75% interest in Chipeta in connection with its August 10, 2006, acquisition of Kerr-McGee Corporation. Anadarko made its initial investment in White Cliffs on January 29, 2007.

Our consolidated financial statements include (i) the combined financial results and operations of AGC and PGT for all periods presented, (ii) the consolidated financial results and operations of Western Gas Partners, LP and its subsidiaries combined with the financial results and operations of MIGC, the Powder River assets, the Granger assets, the MGR assets, the Chipeta assets, the Wattenberg assets, the 0.4% interest in White Cliffs, and the Non-Operated Marcellus Interest, for all periods presented, (iii) the financial results and operations of the Bison assets from 2009 (when Anadarko began construction of such assets, which were subsequently placed in service in June 2010), and (iv) the financial results and operations of the TEFR Interests from 2011 when Anadarko made its initial investment in the respective businesses. Effective August 1, 2012, noncontrolling interests exclude the financial results and operations of the additional Chipeta interest.

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The information in the following table should be read together with the information in the captions How We Evaluate Our Operations, Items Affecting the Comparability of Our Financial Results, Results of Operations, and Key Performance Metrics under 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 2014	2013	2012	2011	2010
Statement of Income Data (for the year ended):					
Total revenues	$1,273,763	$1,029,763	$894,476	$858,144	$655,646
Operating income	451,587	320,858	194,825	245,294	177,539
Net income	390,558	285,443	149,267	206,861	156,933
Net income attributable to noncontrolling interests	14,025	10,816	14,890	14,103	11,005
Net income attributable to Western Gas Partners, LP	376,533	274,627	134,377	192,758	145,928
General partner interest in net income (loss) (1)	120,980	69,633	28,089	8,599	3,067
Limited partners' interest in net income (1)	256,509	200,866	78,897	131,560	111,064
Net income per common unit (basic) (1)	2.13	1.83	0.84	1.64	1.66
Net income per common unit (diluted) (1)	2.12	1.83	0.84	1.64	1.66
Net income per subordinated unit (basic and diluted) (1)	—	—	—	1.28	1.61
Distributions per unit	2.650	2.280	1.960	1.655	1.440
Balance Sheet Data (at period end):					
Total assets	$6,751,631	$4,617,808	$3,863,558	$2,997,689	$2,345,255
Total long-term liabilities	2,537,194	1,535,312	1,284,176	860,092	649,414
Total equity and partners' capital	4,011,866	2,892,036	2,394,076	2,010,279	1,613,311
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$534,807	$448,201	$338,047	$312,838	$252,898
Investing activities	(2,621,559)	(1,652,995)	(1,357,537)	(485,832)	(921,398)
Financing activities	2,053,078	885,541	1,212,912	372,479	625,590
Capital expenditures	(672,821)	(645,854)	(638,121)	(149,717)	(173,891)
Throughput (MMcf/d except throughput measured in barrels):					
Total throughput for natural gas assets	3,658	3,368	3,023	2,715	2,224
Throughput attributable to noncontrolling interests for natural gas assets	165	168	228	242	197
Total throughput attributable to Western Gas Partners, LP for natural gas assets (2)	3,493	3,200	2,795	2,473	2,027
Throughput (MBbls/d) for crude/NGL assets (3)	116	40	31	28	17
Key Performance Metrics (for the year ended):					
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (4)	$822,932	$654,924	$544,853	$516,038	$398,676
Adjusted gross margin for crude/NGL assets (5)	73,714	15,274	13,221	9,497	3,503
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (6)	0.65	0.56	0.53	0.57	0.54
Adjusted gross margin per Bbl for crude/NGL assets (7)	1.75	1.05	1.17	0.94	0.57
Adjusted EBITDA attributable to Western Gas Partners, LP (8)	645,969	457,773	377,929	361,653	264,694

Distributable cash flow [8]	531,136	380,529	309,945	319,294	237,372

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(1) Net income earned on and subsequent to the date of our acquisitions of Partnership assets is allocated to the general partner and the limited partners, including any subordinated and Class C unitholders, in accordance with their respective weighted-average ownership percentages, and when applicable, giving effect to incentive distributions allocable to the general partner. Prior to our acquisition of the Partnership assets, all income is attributed to Anadarko. All subordinated units were converted into common units on August 15, 2011, on a one-for-one basis. For purposes of calculating net income per common and subordinated unit, the conversion of the subordinated units is deemed to have occurred on July 1, 2011. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(2) Includes affiliate, third-party and equity investment throughput, excluding the noncontrolling interest owners' proportionate share of throughput.

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

(4) Calculated as total revenues for natural gas assets less cost of product for natural gas assets plus distributions from our equity investments in Fort Union and Rendezvous, which are measured in Mcf, and excluding the noncontrolling interest owners' proportionate share of revenue and cost of product.

(5) Calculated as total revenues for crude/NGL assets less cost of product for crude/NGL assets plus distributions from our equity investments in White Cliffs, the Mont Belvieu JV, and the TEFR Interests, which are measured in barrels.

(6) Average for period. Calculated as Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (as defined under the caption How We Evaluate Our Operations under Item 7 of this Form 10-K) divided by total throughput (MMcf/d) attributable to Western Gas Partners, LP for natural gas assets.

(7) Average for period. Calculated as Adjusted gross margin for crude/NGL assets (as defined under the caption How We Evaluate Our Operations under Item 7 of this Form 10-K), divided by total throughput (MBbls/d) for crude/NGL assets.

(8) Adjusted EBITDA attributable to Western Gas Partners, LP ("Adjusted EBITDA") and Distributable cash flow are not defined in the generally accepted accounting principles in the United States ("GAAP"). For definitions and reconciliations of Adjusted EBITDA and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please see the caption How We Evaluate Our Operations under 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

Western Gas Partners, LP is a growth-oriented master limited partnership ("MLP") formed by Anadarko Petroleum Corporation in 2007. For purposes of this report, "we," "us," "our," the "Partnership" or "Western Gas Partners" refer to Western Gas Partners, LP and its subsidiaries. Our general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware MLP formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP"). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." All income earned on, distributions from and contributions to, our equity investments are considered to be affiliate transactions. "Equity investment throughput" refers to our 14.81% share of average Fort Union throughput and our 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of our 10% share of average White Cliffs throughput, our 25% share of average Mont Belvieu JV throughput, our 20% share of average TEP and TEG throughput and our 33.33% share of average FRP throughput. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system, and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014. In November 2014, we completed the acquisition of Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM").

The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method by us as of December 31, 2014 (see Note 9—Equity Investments in the Notes to Consolidated Financial Statements under 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 in the Notes to Consolidated Financial Statements under 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.

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 in Item 8 of this Form 10-K.

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EXECUTIVE SUMMARY

We are a growth-oriented Delaware MLP formed by Anadarko to own, operate, acquire and develop midstream energy assets. We currently own or have investments in assets located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas, and are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of December 31, 2014, our assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	1	5	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	13	3	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipeline	1	—	—	1

Significant financial and operational highlights during the year ended December 31, 2014 included the following:

- We completed the acquisition of DBM from a third party. DBM's assets serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. See Acquisitions under Items 1 and 2 of this Form 10-K for additional information.

- We issued 10,913,853 Class C units to a subsidiary of Anadarko, at a price of $68.72 per unit, generating proceeds of $750.0 million, all of which was used to fund a portion of the acquisition of DBM.

- We issued 8,620,153 common units to the public, generating net proceeds of $603.0 million, including the general partner's proportionate capital contribution, part of which was used to fund a portion of the acquisition of DBM.

- We issued 1,133,384 common units to the public under our Continuous Offering Program (as defined and discussed in Registered Securities within this Item 7), generating net proceeds of $83.2 million, including the general partner's proportionate capital contribution. Net proceeds were used for general partnership purposes, including funding capital expenditures. See Equity Offerings under Items 1 and 2 of this Form 10-K for additional information.

- In April 2014, we completed construction and commenced operations of the 300 MMcf/d Train I at the Lancaster plant (located in the DJ Basin complex) in Northeast Colorado. We are currently constructing the 300 MMcf/d Train II at the same plant, with operations expected to commence in the second quarter of 2015.

- We issued $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 and an additional $100.0 million aggregate principal amount of 2.600% Senior Notes due 2018. Net proceeds were used to repay amounts then outstanding under our RCF. See Liquidity and Capital Resources within this Item 7 for additional information.

- We completed the acquisition of Anadarko's 20% interests in TEG and TEP, and its 33.33% interest in FRP. See Acquisitions under Items 1 and 2 of this Form 10-K for additional information.

- We entered into an amended and restated $1.2 billion (expandable to $1.5 billion) senior unsecured RCF replacing our $800.0 million credit facility. See Liquidity and Capital Resources within this Item 7 for additional information.

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- We raised our distribution to $0.70 per unit for the fourth quarter of 2014, representing a 4% increase over the distribution for the third quarter of 2014 and a 17% increase over the distribution for the fourth quarter of 2013.

- Throughput attributable to Western Gas Partners, LP for natural gas assets totaled 3,493 MMcf/d for the year ended December 31, 2014, representing a 9% increase compared to the year ended December 31, 2013.

- 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 $0.65 per Mcf for the year ended December 31, 2014, representing a 16% increase compared to the year ended December 31, 2013.

- Adjusted gross margin for crude/NGL assets (as defined under the caption How We Evaluate Our Operations within this Item 7) averaged $1.75 per Bbl for the year ended December 31, 2014, representing a 67% increase compared to the year ended December 31, 2013.

OUR OPERATIONS

Our results are driven primarily by the volumes of natural gas and NGLs we gather, process, treat or transport through our systems. For the year ended December 31, 2014, 76% of our total revenues and 53% of our throughput (excluding equity investment throughput and throughput measured in barrels) were attributable to transactions with Anadarko. We receive significant dedications from our largest customer, Anadarko. With respect to our Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems, Anadarko has made a dedication to us that will continue to expand as long as additional wells are connected to these gathering systems.

In our gathering operations, we contract with producers and customers to gather natural gas from individual wells located near our gathering systems. We 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 also treat a significant portion of the natural gas that we gather so that it will satisfy required specifications for pipeline transportation.

For the year ended December 31, 2014, 80% of our 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 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. Fee-based gross margin includes equity income from our interests in Fort Union, White Cliffs, Rendezvous, the Mont Belvieu JV and the TEFR Interests.

For the year ended December 31, 2014, 20% of our gross margin, including gross margin attributable to condensate sales, was attributable to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure. A substantial 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. For the year ended December 31, 2014, 99% of our 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. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

We also have indirect exposure to commodity price risk in that persistent low natural gas prices have 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 natural gas available for our systems. We also bear a limited degree of commodity price risk through settlement of natural gas imbalances. Please read Item 7A of this Form 10-K.

As a result of our initial public offering “IPO” and subsequent acquisitions from Anadarko and third parties, our results of operations, financial position and cash flows may vary significantly for 2014, 2013 and 2012 as compared to future periods. Please 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 volumes currently gathered, processed or treated by our competitors. During the year ended December 31, 2014, we added 287 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 general partner’s 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 New York Stock Exchange; and
- independent auditor fees, legal expenses, investor relations expenses, director fees, and registrar and transfer agent fees.

See further detail under Items Affecting the Comparability of Our Financial Results – General and administrative expenses below and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under 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 less cost of product, plus distributions from equity investees and excluding the noncontrolling interest owners' 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, (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, and (iv) costs associated with our fuel-tracking mechanism, which tracks the difference between actual fuel usage and loss, and amounts recovered for estimated fuel usage and loss pursuant to our contracts. These expenses are subject to variability, although a substantial majority of our exposure to commodity price risk attributable to purchases and sales of natural gas, condensate and NGLs is mitigated through our commodity price swap agreements with Anadarko. For a discussion of commodity price swap agreements, see Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under 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 attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less 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, less net cash paid for interest expense (including amortization of deferred debt issuance costs originally paid in cash, offset by non-cash capitalized interest), maintenance capital expenditures, and income taxes. We compare Distributable cash flow to the cash distributions we expect to pay our unitholders. Using this measure, management can quickly compute the Coverage ratio of distributable cash flow to planned cash distributions. We believe Distributable cash flow is useful to investors because this measurement is used by many companies, analysts and others in the industry as a performance measurement tool to evaluate our operating and financial performance and compare it with the performance of other publicly traded partnerships.

While Distributable cash flow is a measure we use to assess our ability to make distributions to our unitholders, it should not be viewed as indicative of the actual amount of cash that we have available for distributions or that we plan to distribute for a given period.

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Reconciliation to GAAP measures. Adjusted gross margin, Adjusted EBITDA and Distributable cash flow are not defined in generally accepted accounting principles in the United States ("GAAP"). The GAAP measure used by us that is most directly comparable to Adjusted gross margin is operating income, while net income 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 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, net income 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, net income 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, net income and net cash provided by operating activities, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

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

	Year Ended December 31,		
thousands	2014	2013	2012
Reconciliation of Adjusted gross margin attributable to Western Gas Partners, LP to Operating income			
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets	$822,932	$654,924	$544,853
Adjusted gross margin for crude/NGL assets	73,714	15,274	13,221
Adjusted gross margin attributable to Western Gas Partners, LP	896,646	670,198	558,074
Adjusted gross margin attributable to noncontrolling interests	20,183	17,416	20,983
Equity income, net	57,836	22,948	16,042
Less:			
Distributions from equity investees	81,022	22,136	20,660
Operation and maintenance	199,305	168,657	140,106
General and administrative	34,242	29,751	99,212
Property and other taxes	25,353	23,244	19,688
Depreciation, amortization and impairments	183,156	145,916	120,608
Operating income	$451,587	$320,858	$194,825

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thousands	Year Ended December 31, 2014	2013	2012
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net income attributable to Western Gas Partners, LP			
Adjusted EBITDA attributable to Western Gas Partners, LP	$645,969	$457,773	$377,929
Less:			
Distributions from equity investees	81,022	22,136	20,660
Non-cash equity-based compensation expense (1)	4,095	3,575	73,508
Interest expense	76,766	51,797	42,060
Income tax expense	2,255	4,219	20,690
Depreciation, amortization and impairments (2)	180,587	143,375	118,279
Other expense (2)	—	175	1,665
Add:			
Equity income, net	57,836	22,948	16,042
Interest income – affiliates	16,900	16,900	16,900
Other income (2) (3)	325	419	368
Income tax benefit	228	1,864	—
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Reconciliation of Adjusted EBITDA attributable to Western Gas Partners, LP to Net cash provided by operating activities			
Adjusted EBITDA attributable to Western Gas Partners, LP	$645,969	$457,773	$377,929
Adjusted EBITDA attributable to noncontrolling interests	16,583	13,348	17,214
Interest income (expense), net	(59,866)	(34,897)	(25,160)
Non-cash equity-based compensation expense (1)	(175)	(54)	(69,791)
Debt-related amortization and other items, net	2,736	2,449	2,319
Current income tax benefit (expense)	556	29,536	9,419
Other income (expense), net (3)	336	253	(1,292)
Distributions from equity investments in excess of cumulative earnings	(18,055)	(4,438)	—
Changes in operating working capital:			
Accounts receivable, net	(4,217)	(34,019)	22,916
Accounts and natural gas imbalance payables and accrued liabilities, net	(52,530)	21,952	5,045
Other	3,470	(3,702)	(552)
Net cash provided by operating activities	$534,807	$448,201	$338,047
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$534,807	$448,201	$338,047
Net cash used in investing activities	(2,621,559)	(1,652,995)	(1,357,537)
Net cash provided by financing activities	2,053,078	885,541	1,212,912

(1) For the year ended December 31, 2012, includes $69.8 million of equity-based compensation associated with the Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated (the “Incentive Plan”) (as defined and described in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K), paid and contributed by Anadarko.

(2) Includes our 51% share prior to August 1, 2012, and our 75% share after August 1, 2012, of depreciation, amortization and impairments; other expense; and other income attributable to Chipeta Processing LLC (“Chipeta”). See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(3) Excludes income of $0.5 million for the year ended December 31, 2014, and $1.6 million for each of the years ended December 31, 2013 and 2012, 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, 2014	2013	2012
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP and calculation of the Coverage ratio			
Distributable cash flow	$531,136	$380,529	$309,945
Less:			
Distributions from equity investees	81,022	22,136	20,660
Non-cash equity-based compensation expense [1]	4,095	3,575	73,508
Interest expense, net (non-cash settled)	—	—	326
Income tax (benefit) expense	2,027	2,355	20,690
Depreciation, amortization and impairments [2]	180,587	143,375	118,279
Other expense [2]	—	175	1,665
Add:			
Equity income, net	57,836	22,948	16,042
Cash paid for maintenance capital expenditures [2] [3]	45,225	29,850	36,459
Capitalized interest [4]	9,832	11,945	6,196
Cash paid for (reimbursement of) income taxes	(90)	552	495
Other income [2] [5]	325	419	368
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Distributions declared [6]			
Limited partners	$320,862		
General partner	121,194		
Total	$442,056		
Coverage ratio	1.20 x		

(1) For the year ended December 31, 2012, includes $69.8 million of equity-based compensation associated with the Incentive Plan (as defined and described in Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K), paid and contributed by Anadarko.

(2) Includes our 51% share prior to August 1, 2012, and our 75% share after August 1, 2012, of depreciation, amortization and impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to Chipeta. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(3) Net of a prior period adjustment reclassifying $0.7 million from capital expenditures to operating expenses for the year ended December 31, 2012.

(4) For the year ended December 31, 2013, includes capitalized interest of $1.4 million for the construction of the Mont Belvieu JV fractionation trains, reflected as a component of the equity investment balance. For the year ended December 31, 2012, excludes $0.6 million of pre-acquisition capitalized interest attributable to the Non-Operated Marcellus Interest systems.

(5) Excludes income of $0.5 million for the year ended December 31, 2014, and $1.6 million for each of the years ended December 31, 2013 and 2012, related to a component of a gas processing agreement accounted for as a capital lease.

(6) Reflects cash distributions of $2.65 per unit declared for the year ended December 31, 2014. See Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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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:

Gathering and processing agreements. The gathering agreements of our initial assets and the Non-Operated Marcellus Interest systems allow for rate resets that target a return on invested capital in those assets over the life of the agreement. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Commodity price swap agreements. We have commodity price swap agreements with Anadarko to mitigate exposure to a substantial majority of the commodity price volatility that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs. Notional volumes for each of the commodity price swap agreements are not specifically defined. Instead, the commodity price swap agreements apply to the actual volume of our natural gas, condensate and NGLs purchased and sold at the Hugoton system and at the DJ Basin and Red Desert complexes, with various expiration dates through December 2016. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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.

General and administrative expenses. Pursuant to the omnibus agreement, Anadarko and the general partner perform centralized corporate functions for us. Prior to our acquisition of the Partnership assets from Anadarko, our historical consolidated financial statements reflect a management services fee, which approximated the general and administrative costs incurred by Anadarko attributable to the Partnership assets. The amounts reimbursed under the omnibus agreement are greater than amounts allocated to us by Anadarko for the aggregate management services fees, and are reflected in our historical consolidated financial statements for periods prior to our acquisition of the Partnership assets from Anadarko. Public company expenses include expenses such as external audit and consulting fees.
The following table summarizes the amounts the Partnership reimbursed to Anadarko:

	Year Ended December 31,		
thousands	2014	2013	2012
General and administrative expenses	$20,249	$16,882	$14,904
Public company expenses	8,006	7,152	6,830
Total reimbursement	$28,255	$24,034	$21,734

We record the equity-based compensation allocated to us by Anadarko as an adjustment to partners' capital in our consolidated financial statements in the period in which it is contributed. During the fourth quarter of 2012, we were allocated $54.9 million of general and administrative expenses from Anadarko associated with the Incentive Plan, which plan was terminated in connection with WGP's IPO. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for further information.

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Noncontrolling interests. Prior to August 1, 2012, the 24% membership interest in Chipeta held by Anadarko and the 25% membership interest in Chipeta held by a third-party were reflected as noncontrolling interests in our consolidated financial statements. On August 1, 2012, we acquired Anadarko's then-remaining 24% membership interest in Chipeta (the "additional Chipeta interest"), receiving distributions related to this additional interest beginning July 1, 2012. Since we acquired an additional interest in an already-consolidated entity, the acquisition of the additional Chipeta interest was accounted for on a prospective basis. As such, effective on the date of acquisition, our noncontrolling interest excludes the financial results and operations of the additional Chipeta interest. The remaining 25% membership interest held by a third-party member is reflected as noncontrolling interest in our consolidated financial statements for all periods presented. See Note 1—Summary of Significant Accounting Policies and Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for further information.

DBM acquisition. In November 2014, we acquired Nuevo Midstream, LLC ("Nuevo") from a third party. Following the acquisition, we changed the name of Nuevo to Delaware Basin Midstream, LLC ("DBM"). We financed the acquisition with the issuance of $750.0 million of Class C units to a subsidiary of Anadarko, borrowings under our senior unsecured revolving credit facility ("RCF") and cash on hand, including the proceeds from the November 2014 equity offering. The assets acquired include cryogenic processing plants, a gas gathering system, and related facilities and equipment, which are collectively referred to as the "DBM complex" and serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. 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 income beginning on the acquisition date in the fourth quarter of 2014.
The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the DBM acquisition using inputs that are not observable in the market and thus represent Level 3 inputs. The fair values of the processing plants, gathering system, and related facilities and equipment are based on market and cost approaches. The fair value of the intangible assets was determined using an income approach. See Note 1—Summary of Significant Accounting Policies and Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for further information.

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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. During 2014, New York Mercantile Exchange ("NYMEX") West Texas Intermediate crude oil daily settlement prices ranged from a high of $107.26 per barrel to a low of $53.27 per barrel at the end of 2014. Daily settlement prices for NYMEX Henry Hub gas ranged from a high of $6.15 MMBtu to a low of $2.89 per MMBtu during 2014. The duration and magnitude of the recent decline in crude oil prices cannot be predicted. This decline in crude oil prices will likely result in most, if not all, of our customers, including Anadarko, reducing capital expenditures in 2015 versus 2014 and focusing a larger share of their capital expenditures on longer term opportunities.

Furthermore, over the last five years, the relatively low natural gas price environment has led to lower levels of drilling activity in dry-gas basins served by certain of our assets. Several of our customers, including Anadarko, have reduced activity levels in those areas, shifting capital toward liquid-rich opportunities that offer higher margins and superior economics. This trend has 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 natural gas 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 areas focused on longer term growth where anticipated returns are less sensitive to spot crude oil and natural gas prices. We will continue to evaluate the crude oil and natural gas price environments and adjust capital spending plans as prices fluctuate while maintaining the appropriate liquidity and financial flexibility.

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.

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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.

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 were at or near historic lows at certain times during 2014. Should interest rates rise, our financing costs would increase accordingly. 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, 2014, Anadarko’s total domestic midstream asset portfolio, excluding the assets we own, consisted of 17 gathering systems, 4,426 miles of pipeline and 9 processing and/or treating facilities. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time.
As of December 31, 2014, WGP held a 34.9% limited partner interest in us, and through its ownership of our general partner, WGP indirectly held a 1.8% general partner interest in us and 100% of our incentive distribution rights. As of December 31, 2014, other subsidiaries of Anadarko separately held an aggregate 8.3% 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. 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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RESULTS OF OPERATIONS

OPERATING RESULTS

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

	Year Ended December 31,		
thousands	2014	2013	2012
Gathering, processing and transportation of natural gas and natural gas liquids	$647,451	$482,542	$382,330
Natural gas, natural gas liquids and condensate sales	612,854	541,244	508,339
Other	13,458	5,977	3,807
Total revenues (1)	1,273,763	1,029,763	894,476
Equity income, net	57,836	22,948	16,042
Total operating expenses (1)	880,012	731,853	715,693
Operating income	451,587	320,858	194,825
Interest income – affiliates	16,900	16,900	16,900
Interest expense	(76,766)	(51,797)	(42,060)
Other income (expense), net	864	1,837	292
Income before income taxes	392,585	287,798	169,957
Income tax (benefit) expense	2,027	2,355	20,690
Net income	390,558	285,443	149,267
Net income attributable to noncontrolling interests	14,025	10,816	14,890
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Key performance metrics (2)			
Adjusted gross margin attributable to Western Gas Partners, LP	$896,646	$670,198	$558,074
Adjusted EBITDA attributable to Western Gas Partners, LP	645,969	457,773	377,929
Distributable cash flow	531,136	380,529	309,945

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

(2) Adjusted gross margin attributable to Western Gas Partners, LP, Adjusted EBITDA attributable to Western Gas Partners, LP and Distributable cash flow are defined under the caption How We Evaluate Our Operations—Non-GAAP financial measures 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 GAAP Measures within this Item 7.

For purposes of the following discussion, any increases or decreases “for the year ended December 31, 2014” refer to the comparison of the year ended December 31, 2014, to the year ended December 31, 2013, and any increases or decreases “for the year ended December 31, 2013” refer to the comparison of the year ended December 31, 2013, to the year ended December 31, 2012.

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Throughput

MMcf/d (except throughput measured in barrels)	Year Ended December 31, 2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Throughput for natural gas assets					
Gathering, treating and transportation [1]	1,562	1,404	11 %	1,264	11 %
Processing [1]	1,925	1,758	9 %	1,524	15 %
Equity investment [2]	171	206	(17)%	235	(12)%
Total throughput for natural gas assets	3,658	3,368	9 %	3,023	11 %
Throughput attributable to noncontrolling interests for natural gas assets	165	168	(2)%	228	(26)%
Total throughput attributable to Western Gas Partners, LP for natural gas assets [3]	3,493	3,200	9 %	2,795	14 %
Total throughput (MBbls/d) for crude/NGL assets [4]	116	40	190 %	31	29 %

(1) The combination of our Wattenberg and Platte Valley systems in 2014 into the entity now referred to as the “DJ Basin complex” (which also includes the Lancaster plant) resulted in the following: (i) the Wattenberg system throughput previously reported as “Gathering, treating and transportation” is now reported as “Processing” for all periods presented, and (ii) beginning in 2014, throughput both gathered and processed by the two systems is no longer separately reported.

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

(3) Includes affiliate, third-party and equity investment throughput (as equity investment throughput is defined in the above footnote), excluding the noncontrolling interest owners’ proportionate share of throughput.

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

Gathering, treating and transportation throughput increased by 158 MMcf/d for the year ended December 31, 2014, due to increased throughput on the Non-Operated Marcellus Interest systems as a result of additional well connections and additional throughput on the Anadarko-Operated Marcellus Interest systems after the March 2013 acquisition, partially offset by throughput decreases at the Bison facility due to a period of reduced flow resulting from planned maintenance activity and decreases at the Pinnacle and Dew systems resulting from natural production declines in those areas.

Gathering, treating and transportation throughput increased by 140 MMcf/d for the year ended December 31, 2013, due to increased throughput on the Non-Operated Marcellus Interest systems and additional throughput on the Anadarko-Operated Marcellus Interest systems beginning in March 2013. These increases were partially offset by decreases at the Bison facility resulting from reduced drilling activity in the area, at MIGC due to the expiration of a firm transportation agreement effective September 2012 and at the Pinnacle, Dew and Haley systems resulting from natural production declines in those areas.

Processing throughput increased by 167 MMcf/d for the year ended December 31, 2014, primarily due to the start-up of the Brasada complex in June 2013, increased volumes processed at a plant included in the MGR acquisition (the “Granger straddle plant”) and the acquisition of DBM in November 2014.

Processing throughput increased by 234 MMcf/d for the year ended December 31, 2013, primarily due to throughput increases at Chipeta and the DJ Basin complex, the start-up of the Brasada complex in June 2013, and an increase in volumes at the Red Desert complex due to additional well connections during the period. In addition, increased volumes processed at the Granger straddle plant contributed to the increase. These increases were partially offset by a decrease in throughput at the Granger complex due to natural production declines in the area.

Equity investment throughput decreased by 35 MMcf/d for the year ended December 31, 2014, primarily due to lower throughput at the Fort Union system due to production declines in the area and volumes being diverted to the third-party Bison pipeline. Equity investment volumes decreased by 29 MMcf/d for the year ended December 31, 2013, primarily due to lower throughput at the Fort Union system due to production declines in the area.

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Throughput for crude/NGL assets measured in barrels increased by 76 MBbls/d for the year ended December 31, 2014, due to the start-up of (i) the Mont Belvieu JV fractionation trains, TEP and TEG in the fourth quarter of 2013, and (ii) FRP in March 2014. Throughput for crude/NGL assets measured in barrels increased by 9 MBbls/d for the year ended December 31, 2013, primarily due to the start-up of the Mont Belvieu JV fractionation trains, TEP and TEG in the fourth quarter of 2013.

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

	Year Ended December 31,						
thousands except percentages	2014	2013	Inc/ (Dec)		2012	Inc/ (Dec)	
Gathering, processing and transportation of natural gas and natural gas liquids	$647,451	$482,542	34	%	$382,330	26	%

Revenues from gathering, processing and transportation of natural gas and natural gas liquids increased by $164.9 million for the year ended December 31, 2014, primarily due to increases of (i) $67.2 million resulting from increased throughput at the DJ Basin complex and the start-up of the Lancaster plant in April 2014, (ii) $30.1 million due to the start-up of the Brasada complex in June 2013, (iii) $28.8 million due to higher throughput on the Non-Operated Marcellus Interest systems, partially offset by a lower average gathering rate, (iv) $12.4 million due to higher throughput and average gathering rate on the Anadarko-Operated Marcellus Interest systems, acquired in March 2013, (v) $9.7 million due to increased throughput at Chipeta's Train III, as well as the retroactive application of a fee increase in the third quarter of 2014 that was applicable upon Train III being placed into service, (vi) $6.3 million due to new third-party gathering agreements at the Hilight system, and (vii) $3.7 million due to the acquisition of the DBM complex in November 2014.
Revenues from gathering, processing and transportation of natural gas and natural gas liquids increased by $100.2 million for the year ended December 31, 2013, primarily due to increases of $30.5 million, $20.8 million, and $15.3 million from the Non-Operated Marcellus Interest systems, the DJ Basin complex, and Chipeta, respectively, all due to higher throughput, an increase of $14.1 million due to the acquisition of the Anadarko-Operated Marcellus Interest systems beginning in March 2013, and an increase of $16.3 million due to the start-up of the Brasada complex in June 2013.

Natural Gas, Natural Gas Liquids and Condensate Sales

	Year Ended December 31,						
thousands except percentages and per-unit amounts	2014	2013	Inc/ (Dec)		2012	Inc/ (Dec)	
Natural gas sales	$159,144	$118,134	35	%	$101,116	17	%
Natural gas liquids sales	417,459	391,608	7	%	377,377	4	%
Drip condensate sales	36,251	31,502	15	%	29,846	6	%
Total	$612,854	$541,244	13	%	$508,339	6	%
Average price per unit:							
Natural gas (per Mcf)	$4.18	$4.58	(9	)%	$4.24	8	%
Natural gas liquids (per Bbl)	47.34	47.69	(1	)%	48.22	(1	)%
Drip condensate (per Bbl)	80.83	76.62	5	%	75.88	1	%

For the years ended December 31, 2014 and 2013, average natural gas, NGL and drip condensate prices included the effects of commodity price swap agreements attributable to sales for the Hilight, Hugoton and Newcastle systems, and for the DJ Basin, Granger and Red Desert complexes. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $71.6 million for the year ended December 31, 2014, consisting of $41.0 million in natural gas sales, $25.9 million in NGLs sales and $4.7 million in drip condensate sales.

The growth in natural gas sales for the year ended December 31, 2014, was primarily due to increases of (i) $17.1 million at the DJ Basin complex due to an increase in both volumes sold and average swap prices, (ii) $15.9 million at the Hilight system due to an increase in volumes sold, partially offset by a decrease in average swap price, (iii) $4.2 million at the Granger complex due to an increase in volumes sold as a result of new plant purchase contracts effective in September 2014, and (iv) $3.5 million at the Red Desert complex due to an increase in volumes sold.

The growth in NGLs sales for the year ended December 31, 2014, was primarily due to increases of (i) $21.2 million at the DJ Basin complex due to an increase in volumes sold, partially offset by a decrease in average swap price, (ii) $10.5 million at the Hilight system due to higher volumes processed and sold, partially offset by a decrease in average swap price, and (iii) $8.0 million at Chipeta due to an increase in volumes sold, partially offset by a decrease in average price. These increases were partially offset by a $13.7 million decrease at the Red Desert complex due to a decrease in volumes sold.

The increase in drip condensate sales for the year ended December 31, 2014, was primarily due to an increase of $6.0 million at the DJ Basin complex from an increase in volumes sold and average swap price, partially offset by a decrease of $1.4 million at the Hugoton system due to a decrease in volumes sold.

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $32.9 million for the year ended December 31, 2013, due to a $17.0 million increase in natural gas sales, a $14.2 million increase in NGLs sales and a $1.7 million increase in drip condensate sales.

The growth in natural gas sales for the year ended December 31, 2013, was primarily due to an 8% increase in the overall sales price of natural gas, as well as higher sales volumes at the DJ Basin and Red Desert complexes, partially offset by a decrease at the DJ Basin complex due to a gas flow change that became effective in July 2013, whereby volumes previously processed under percentage-of-proceeds contracts are now processed under fee-based arrangements.

The growth in NGLs sales for the year ended December 31, 2013, was primarily due to increases of $22.1 million, $15.4 million, $9.0 million and $4.2 million resulting from higher volumes processed and sold at the Red Desert complex, the Hilight system, the DJ Basin complex and the Granger straddle plant, respectively. These increases were partially offset by a decrease of $14.0 million at Chipeta (with a corresponding decrease in cost of product), a decrease of $12.8 million at the DJ Basin complex due to the aforementioned gas flow changes, and a decrease of $9.1 million at the Granger complex due to a decrease in volumes sold as a result of decreased throughput.

The growth in drip condensate sales for the year ended December 31, 2013 was primarily due to a $2.4 million increase at the DJ Basin complex due to an increase in volumes sold as a result of increased throughput, partially offset by a $0.9 million decrease at the Hugoton system due to a decrease in volumes sold as a result of decreased throughput.

Other Revenues

	Year Ended December 31,				
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Other revenues	$13,458	$5,977	125 %	$3,807	57 %

For the year ended December 31, 2014, other revenues increased by $7.5 million, primarily due to a $4.7 million settlement of a business interruption insurance claim at Chipeta in 2013 and changes in imbalance positions at the DJ Basin complex. For the year ended December 31, 2013, other revenues increased by $2.2 million, primarily due to the collection of deficiency fees associated with volume commitments at Chipeta.

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Equity Income, Net

	Year Ended December 31,					
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)	
Equity income, net	$57,836	$22,948	152 %	$16,042	43	%

For the year ended December 31, 2014, equity income, net increased by $34.9 million, primarily driven by the start-up of (i) the Mont Belvieu JV fractionation trains in the fourth quarter of 2013, (ii) TEG and TEP in the fourth quarter of 2013 and (iii) FRP in March 2014. For the year ended December 31, 2013, equity income, net increased by $6.9 million, primarily due to the start-up of the Mont Belvieu JV fractionation trains in the fourth quarter of 2013, and volume increases at White Cliffs. These increases were offset by net losses associated with the initial start-up and line-fill stage of TEP during the fourth quarter of 2013.

Cost of Product and Operation and Maintenance Expenses

	Year Ended December 31,					
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)	
NGL purchases	$228,369	$191,788	19 %	$181,078	6	%
Residue purchases	178,701	155,559	15 %	143,962	8	%
Other	30,886	16,938	82 %	11,039	53	%
Cost of product	437,956	364,285	20 %	336,079	8	%
Operation and maintenance	199,305	168,657	18 %	140,106	20	%
Total cost of product and operation and maintenance expenses	$637,261	$532,942	20 %	$476,185	12	%

Cost of product expense for the years ended December 31, 2014, 2013 and 2012, included the effects of commodity price swap agreements attributable to purchases for the Hilight, Hugoton and Newcastle systems, and for the DJ Basin, Granger and Red Desert complexes. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.
Including the effects of commodity price swap agreements on purchases, cost of product expense for the year ended December 31, 2014, increased by $73.7 million, primarily due to the volume fluctuations noted in Throughput and Natural Gas, Natural Gas Liquids and Condensate Sales within this Item 7, resulting in the following:

- a $36.6 million net increase in NGL purchases primarily at the DJ Basin complex, Hilight system, the DBM complex and Chipeta, partially offset by a decrease at the Red Desert complex;

- a $23.1 million net increase in residue purchases, primarily driven by higher volumes at the Hilight system, the DJ Basin complex and Chipeta; and

- a $13.9 million net increase in other items, primarily due to changes in imbalance positions at the DJ Basin complex.

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Including the effects of commodity price swap agreements on purchases, cost of product expense for the year ended December 31, 2013, increased by $28.2 million, primarily due to the volume fluctuations noted in Throughput and Natural Gas, Natural Gas Liquids and Condensate Sales within this Item 7, resulting in the following:

- an $11.6 million net increase in residue purchases primarily at the DJ Basin and the Red Desert complexes, partially offset by decreases at the Granger complex;
- a $10.7 million net increase in NGL purchases primarily at the Red Desert complex, the Hilight system and the DJ Basin complex, partially offset by decreases at Chipeta and the Granger complex; and
- a $5.9 million net increase in other items, primarily due to gas compression expenses at the Granger complex and changes in imbalance positions primarily at the DJ Basin complex, and the Hilight and Hugoton systems.

Operation and maintenance expense increased by $30.6 million for the year ended December 31, 2014, primarily due to an increase of $13.0 million for plant repairs and maintenance primarily at the Hilight system, and DJ Basin and Brasada complexes, an increase of $8.0 million in utilities, contract labor and consulting, water and treating costs at the DJ Basin complex and a $4.4 million increase in property, facility and overhead expense attributable to the Non-Operated Marcellus Interest systems.

Operation and maintenance expense increased by $28.6 million for the year ended December 31, 2013, primarily due to an increase of $9.7 million in property, facility and overhead expense attributable to the Non-Operated Marcellus Interest systems, an increase of $8.3 million for plant repairs and maintenance primarily at the DJ Basin complex and Chipeta, and an increase of $7.7 million for salaries, wages and payroll tax expense primarily at the DJ Basin and Brasada complexes and the Hilight system.

General and Administrative, Depreciation and Other Expenses

	Year Ended December 31,				
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
General and administrative	$34,242	$29,751	15 %	$99,212	(70)%
Property and other taxes	25,353	23,244	9 %	19,688	18 %
Depreciation, amortization and impairments	183,156	145,916	26 %	120,608	21 %
Total general and administrative, depreciation and other expenses	$242,751	$198,911	22 %	$239,508	(17)%

General and administrative expenses increased by $4.5 million for the year ended December 31, 2014, primarily due to an increase of $3.2 million in personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement, an increase of $0.5 million in non-cash compensation expenses, and $0.5 million in consulting and audit fees.

General and administrative expenses decreased by $69.5 million for the year ended December 31, 2013, primarily due to a decrease of $69.9 million in non-cash compensation expenses attributable to the awards outstanding under the Incentive Plan, which were settled in December 2012 when the Incentive Plan terminated in conjunction with WGP's IPO. These declines were partially offset by an increase of $2.2 million in corporate and management personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement.

Property and other taxes increased by $2.1 million for the year ended December 31, 2014, primarily due to ad valorem tax increases of $2.4 million associated with capital additions at Chipeta, the completion of the Brasada complex in June 2013, the start-up of Train I at the Lancaster plant in April 2014 and the acquisition of the DBM complex in November 2014. These increases were offset by a decrease of $0.3 million in accrued ad valorem taxes at the Hugoton system.

Property and other taxes increased by $3.6 million for the year ended December 31, 2013, primarily due to ad valorem tax increases of $2.6 million associated with capital additions at the DJ Basin complex and Chipeta and $0.9 million due to the completion of the Brasada complex in June 2013.

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Depreciation, amortization and impairments increased by $37.2 million for the year ended December 31, 2014, primarily attributable to a $16.5 million increase in depreciation expense associated with the start-up of Train I at the Lancaster plant in April 2014 and compression expansion capital projects at the DJ Basin complex, a $4.6 million increase in depreciation expense due to the acquisition of the DBM complex in November 2014, a $3.9 million increase in depreciation expense due to the completion of the Brasada complex in June 2013, a $3.8 million increase in depreciation expense at the Non-Operated Marcellus Interest systems driven by additional capital projects, a $2.1 million increase in depreciation expense related to the September 2013 acquisition of OTTCO, a $2.0 million and $1.2 million increase in depreciation expense at the Hilight system and the Anadarko-Operated Marcellus Interest systems, respectively, related to capital projects, and an impairment of $1.0 million in the first quarter of 2014 related to a non-operational plant in the Powder River Basin that was impaired to its estimated fair value of $2.4 million, using Level 3 fair value inputs, with no comparative activity in the prior period. In addition, during the year ended December 31, 2014, an impairment of $0.8 million was recognized due to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems and an impairment of $0.5 million was recognized due to a compressor no longer being in service at the Hilight system.
Depreciation, amortization and impairments increased by $25.3 million for the year ended December 31, 2013, primarily attributable to a $12.1 million increase in depreciation expense associated with capital projects completed at the DJ Basin complex, Chipeta and Hilight system, a $6.2 million increase in depreciation and impairment expense at the Non-Operated Marcellus Interest systems, a $6.1 million increase in depreciation expense related to the completion of the Brasada complex in June 2013, and a $3.9 million increase in depreciation expense associated with the March 2013 acquisition of the Anadarko-Operated Marcellus Interest systems. Partially offsetting these increases was a decrease of $5.3 million in impairment expense, due to a $1.2 million impairment recognized in 2013 primarily related to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems, as compared to the $6.6 million impairment recognized in 2012 related to a gathering system in central Wyoming and a relocated compressor.

Interest Income – Affiliates and Interest Expense

	Year Ended December 31,				
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Interest income on note receivable	$16,900	$16,900	— %	$16,900	— %
Interest income – affiliates	$16,900	$16,900	— %	$16,900	— %
Third parties					
Interest expense on long-term debt	$(81,495)	$(59,293)	37 %	$(41,171)	44 %
Amortization of debt issuance costs and commitment fees	(5,103)	(4,449)	15 %	(4,319)	3 %
Capitalized interest	9,832	11,945	(18)%	6,196	93 %
Affiliates					
Interest expense on note payable to Anadarko (1)	—	—	— %	(2,440)	(100)%
Interest expense on affiliate balances (2)	—	—	— %	(326)	(100)%
Interest expense	$(76,766)	$(51,797)	48 %	$(42,060)	23 %

(1) In June 2012, the note payable to Anadarko was repaid in full. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(2) Imputed interest expense on the reimbursement payable to Anadarko for certain expenditures incurred in 2011 related to the construction of the Brasada complex and Lancaster plant. In the fourth quarter of 2012, we repaid the reimbursement payable to Anadarko associated with the construction of the Brasada complex and Lancaster plant. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Interest expense increased by $25.0 million for the year ended December 31, 2014, primarily due to interest expense incurred on the 5.450% Senior Notes due 2044 of $17.0 million, as well as additional interest incurred on the 2.600% Senior Notes due 2018 of $6.1 million. Amortization of debt issuance costs and commitment fees increased by $0.7 million for the year ended December 31, 2014, primarily due to higher commitment fees driven by the amendment and restatement of the RCF from $800.0 million to $1.2 billion in February 2014. Capitalized interest decreased by $2.1 million for the year ended December 31, 2014, primarily due to the completion of the Brasada complex in June 2013, partially offset by an increase in capitalized interest for the construction of Train II at the Lancaster plant in the DJ Basin complex. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Interest expense increased by $9.7 million for the year ended December 31, 2013, primarily due to interest expense incurred on the 2022 Notes of $15.0 million as well as interest incurred on the 2018 Notes of $2.5 million. In addition, interest expense increased on the RCF by $0.6 million primarily due to greater average outstanding borrowings in the period, partially offset by a decrease of $2.4 million attributable to the repayment of the note payable to Anadarko in June 2012. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Also partially offsetting the increases in interest expense for the year ended December 31, 2013, was an increase of capitalized interest of $5.7 million primarily associated with the expansion of the Lancaster plant and construction of the two Mont Belvieu JV fractionation trains.

Income Tax (Benefit) Expense

	Year Ended December 31,				
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Income before income taxes	$392,585	$287,798	36 %	$169,957	69 %
Income tax (benefit) expense	2,027	2,355	(14)%	20,690	(89)%
Effective tax rate	1 %	1 %		12 %	

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

Income attributable to (a) the TEFR Interests prior to and including February 2014, (b) the Non-Operated Marcellus Interest systems prior to and including February 2013 and (c) the MGR assets prior to and including January 2012, was subject to federal and state income tax. Income earned on the TEFR Interests, the Non-Operated Marcellus Interest systems and MGR assets for periods subsequent to February 2014, February 2013, and January 2012, respectively, was only subject to Texas margin tax on income apportionable to Texas.

Noncontrolling Interests

	Year Ended December 31,				
thousands except percentages	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Net income attributable to noncontrolling interests	$14,025	$10,816	30 %	$14,890	(27)%

For the year ended December 31, 2014, net income attributable to noncontrolling interests increased by $3.2 million, primarily due to increased revenues at Chipeta driven by increased drilling activities in the Uinta Basin. For the year ended December 31, 2013, net income attributable to noncontrolling interests decreased by $4.1 million, primarily due to our acquisition of the additional Chipeta interest in August 2012.

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KEY PERFORMANCE METRICS

	Year Ended December 31,					
thousands except percentages and per-unit amounts	2014	2013	Inc/ (Dec)	2012	Inc/ (Dec)
Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets (1)	$822,932	$654,924	26 %	$544,853	20 %
Adjusted gross margin for crude/NGL assets (2)	73,714	15,274	NM	13,221	16 %
Adjusted gross margin attributable to Western Gas Partners, LP (3)	896,646	670,198	34 %	558,074	20 %
Adjusted gross margin per Mcf attributable to Western Gas Partners, LP for natural gas assets (4)	0.65	0.56	16 %	0.53	6 %
Adjusted gross margin per Bbl for crude/NGL assets (5)	1.75	1.05	67 %	1.17	(10)%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	645,969	457,773	41 %	377,929	21 %
Distributable cash flow (3)	531,136	380,529	40 %	309,945	23 %

(1) Adjusted gross margin attributable to Western Gas Partners, LP for natural gas assets is calculated as total revenues for natural gas assets less cost of product for natural gas assets plus distributions from our equity investments in Fort Union and Rendezvous, and excluding the noncontrolling interest owners' 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 for crude/NGL assets less 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 attributable to Western Gas Partners, LP. Adjusted gross margin increased by $226.4 million for the year ended December 31, 2014, primarily due to higher margins at the DJ Basin complex (including the start-up of the Lancaster plant in April 2014), the start-up of the Mont Belvieu fractionation trains in the fourth quarter of 2013, the start-up of the Brasada complex in June 2013, higher margins on the Non-Operated Marcellus Interest systems, the acquisition of the Anadarko-Operated Marcellus Interest in March 2013, the start-up of TEG and TEP in the fourth quarter of 2013, and the start-up of FRP in March 2014.

Adjusted gross margin increased by $112.1 million for the year ended December 31, 2013, primarily due to higher margins at the Non-Operated Marcellus Interest systems, the DJ Basin complex, the Anadarko-Operated Marcellus Interest systems and Chipeta, and the start-up of the Brasada complex in June 2013.

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, 2014, primarily due to the consolidation of several systems into the DJ Basin complex beginning in 2014, as well as the start-up of the Lancaster plant in April 2014, and higher margins at Chipeta and the

Non-Operated Marcellus Interest systems.

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, 2013, primarily due to higher margins and increases in throughput at Chipeta, the DJ Basin complex, and the Non-Operated Marcellus Interest systems, as well as overall changes in the throughput mix of our portfolio.

Adjusted gross margin per Bbl for crude/NGL assets increased by $0.70 for the year ended December 31, 2014, due to distributions received from the Mont Belvieu JV and the TEFR Interests. Adjusted gross margin per Bbl for crude/NGL assets decreased by $0.12 for the year ended December 31, 2013, primarily due to net losses associated with the initial start-up and line-fill stage of TEP during the fourth quarter of 2013.

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Adjusted EBITDA. Adjusted EBITDA increased by $188.2 million for the year ended December 31, 2014, primarily due to a $244.0 million increase in total revenues and a $58.9 million increase in distributions from equity investees. These amounts were offset by a $73.7 million increase in cost of product, a $30.6 million increase in operation and maintenance expenses, a $4.0 million increase in general and administrative expenses excluding non-cash equity-based compensation expense, a $3.2 million increase in net income attributable to noncontrolling interests, and a $2.1 million increase in property and other tax expense.

Adjusted EBITDA increased by $79.8 million for the year ended December 31, 2013, primarily due to a $135.3 million increase in total revenues and a $4.1 million decrease in net income attributable to noncontrolling interests as a result of the acquisition of the additional Chipeta interest. These amounts were offset by a $28.6 million increase in operation and maintenance expenses, a $28.2 million increase in cost of product, and a $3.6 million increase in property and other tax expense.

Distributable cash flow. Distributable cash flow increased by $150.6 million for the year ended December 31, 2014, primarily due to a $188.2 million increase in Adjusted EBITDA, offset by a $22.9 million increase in net cash paid for interest expense and a $15.4 million increase in cash paid for maintenance capital expenditures.

Distributable cash flow increased by $70.6 million for the year ended December 31, 2013, primarily due to a $79.8 million increase in Adjusted EBITDA and a $6.6 million decrease in maintenance capital expenditures, offset by a $15.8 million increase in net cash paid for interest expense.

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, 2014, included cash and cash equivalents, cash flows generated from operations, interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional equity or debt securities. We believe that cash flows generated from these sources will be sufficient to satisfy our short-term working capital requirements and long-term maintenance and expansion capital expenditure requirements. The amount of future distributions to unitholders will depend on our results of operations, financial condition, capital requirements and other factors, and will be determined by the Board of Directors of our general partner on a quarterly basis. Due to our cash distribution policy, we expect to rely on external financing sources, including equity and debt issuances, to fund expansion capital expenditures and future acquisitions. However, to limit interest expense, we may use operating cash flows to fund expansion capital expenditures or acquisitions, which could result in subsequent borrowings under our RCF to pay distributions or fund other short-term working capital requirements.

Our partnership agreement requires that we distribute all of our available cash (as defined in the partnership agreement) to unitholders of record on the applicable record date within 45 days of the end of each quarter. We have made cash distributions to our unitholders each quarter since our IPO and have increased our quarterly distribution each quarter since the second quarter of 2009. On January 22, 2015, the Board of Directors of our general partner declared a cash distribution to our unitholders of $0.700 per unit, or $126.0 million in aggregate, including incentive distributions, but excluding distributions on Class C units. The cash distribution was paid on February 12, 2015, to unitholders of record at the close of business on February 2, 2015. In connection with the closing of the DBM acquisition in November 2014, we issued Class C units that will receive distributions in the form of additional Class C units until the end of 2017, unless earlier converted (see Note 3—Partnership Distributions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). The Class C unit prorated distribution, if paid in cash, would have been $3.1 million for the fourth quarter of 2014.

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

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Working capital. As of December 31, 2014, we had a $27.3 million working capital deficit, which we define as the amount by which current liabilities exceed current assets. Working capital is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. Our working capital deficit as of December 31, 2014, was primarily due to the costs incurred related to projects at the DJ Basin complex, which include the continued construction of Train II at the Lancaster plant and compressor expansions, as well as the DBM acquisition. As of December 31, 2014, we had $677.2 million available for borrowing under our RCF.

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.

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	2014	2013	2012
Acquisitions	$1,902,520	$716,985	$611,719
Expansion capital expenditures	$627,140	$615,924	$600,893
Maintenance capital expenditures	45,681	29,930	37,228
Total capital expenditures (1) (2) (3)	$672,821	$645,854	$638,121
Capital incurred (2) (4)	$695,350	$628,285	$690,041

(1) Maintenance capital expenditures for the years ended December 31, 2014, 2013 and 2012, are presented net of $0.2 million, $0.6 million and zero, respectively, of contributions in aid of construction costs from affiliates.

(2) Includes the noncontrolling interest owners' share of Chipeta's capital expenditures, funded by contributions from the noncontrolling interest owners for all periods presented. For the years ended December 31, 2014, 2013 and 2012, included $9.8 million, $10.6 million and $6.8 million, respectively, of capitalized interest.

(3) Capital expenditures for the year ended December 31, 2012, included $178.8 million of pre-acquisition capital for the Non-Operated Marcellus Interest systems.

(4) Capital incurred for the years ended December 31, 2013 and 2012, included $8.8 million and $160.9 million, respectively, of pre-acquisition capital incurred for the Non-Operated Marcellus Interest systems.

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Acquisitions during 2014 included DBM and the TEFR Interests. Acquisitions during 2013 included OTTCO, the Mont Belvieu JV, the Anadarko-Operated Marcellus Interest and the Non-Operated Marcellus Interest. Acquisitions during 2012 included the additional Chipeta interest and the MGR assets. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.
Capital expenditures, excluding acquisitions, increased by $27.0 million for the year ended December 31, 2014. Expansion capital expenditures increased by $11.2 million (including a $0.8 million decrease in capitalized interest) for the year ended December 31, 2014, primarily due to an increase of $111.0 million at the DJ Basin complex, related to compression projects and well connections, as well as the continued construction of Train II at the Lancaster plant. In addition, there was an increase of $21.7 million at the Haley system, $21.6 million at the Hilight system, $13.3 million at the DBM complex, $11.9 million at the Anadarko-Operated Marcellus Interest systems and $6.2 million at Chipeta. These increases were partially offset by a $104.1 million decrease at the Brasada complex due to construction being completed in June 2013, a $68.6 million decrease at the Non-Operated Marcellus Interest systems and a $2.3 million decrease at the Red Desert complex. Maintenance capital expenditures increased by $15.8 million, primarily as a result of increased expenditures of $4.7 million at the DJ Basin complex, $5.7 million at the Non-Operated Marcellus Interest systems, $2.2 million at the Red Desert complex and $1.6 million at the Anadarko-Operated Marcellus Interest systems.
Capital expenditures, excluding acquisitions, increased by $7.7 million for the year ended December 31, 2013. Expansion capital expenditures increased by $15.0 million (including a $3.8 million increase in capitalized interest) for the year ended December 31, 2013, primarily due to an increase of $151.2 million at the DJ Basin complex related to compression projects and the continued construction of Train I at the Lancaster plant, and a $43.1 million increase in expenditures at the Hilight system and at the Anadarko-Operated Marcellus Interest systems. These increases were partially offset by a $180.0 million decrease at Chipeta, the Non-Operated Marcellus Interest systems and the Brasada complex. Maintenance capital expenditures decreased by $7.3 million, primarily as a result of decreased expenditures of $7.5 million at the DJ Basin and Red Desert complexes, the Hilight and Haley systems, and the Non-Operated Marcellus Interest systems, partially offset by a $1.7 million increase at the Anadarko-Operated Marcellus Interest systems.
Excluding acquisitions, we expect to spend 38% of our 2015 capital budget in the Rocky Mountains - Colorado area, 36% in West Texas and 18% in North-central Pennsylvania, with the remainder spent in other areas in which we operate.

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	2014	2013	2012
Net cash provided by (used in):			
Operating activities	$534,807	$448,201	$338,047
Investing activities	(2,621,559)	(1,652,995)	(1,357,537)
Financing activities	2,053,078	885,541	1,212,912
Net increase (decrease) in cash and cash equivalents	$(33,674)	$(319,253)	$193,422

Operating Activities. Net cash provided by operating activities during the years ended December 31, 2014 and 2013, increased primarily due to the impact of changes in working capital items. This increase was driven primarily by changes in accounts payable balances due to the acquisition of DBM and timing of payments made to third-parties. Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods.

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Investing Activities. 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;
- $672.8 million of capital expenditures, net of $0.2 million of contributions in aid of construction costs from affiliates, primarily related to projects at the DJ Basin complex, which include the continued construction of Train II at the Lancaster plant and compressor expansions;
- $356.3 million of cash paid for the acquisition of the TEFR Interests;
- $42.0 million of cash paid related to FRP construction, which was completed in March 2014;
- $22.9 million of cash paid for equipment purchases from Anadarko;
- $18.1 million of distributions from equity investments in excess of cumulative earnings;
- $10.5 million of cash paid for a White Cliffs expansion project; and
- $6.6 million of cash paid related to TEP construction, which was completed in November 2013.

Net cash used in investing activities for the year ended December 31, 2013, included the following:

- $646.5 million of capital expenditures, net of $0.6 million of contributions in aid of construction costs from affiliates;
- $465.5 million of cash paid for the Non-Operated Marcellus Interest acquisition;
- $236.9 million of capital contributions to TEG, TEP and FRP for construction costs;
- $134.6 million of cash paid for the Anadarko-Operated Marcellus Interest acquisition;
- $78.1 million of cash paid for the Mont Belvieu JV acquisition;
- $38.7 million of capital contributions to the Mont Belvieu JV to fund our share of construction costs for the fractionation trains completed in the fourth quarter of 2013;
- $27.5 million of cash paid for the OTTCO acquisition;
- $19.1 million of cash paid for a White Cliffs expansion project;
- $11.2 million of cash paid for equipment purchases from Anadarko; and
- $4.4 million of distributions from equity investments in excess of cumulative earnings.

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Net cash used in investing activities for the year ended December 31, 2012, included the following:

- $638.1 million of capital expenditures;
- $458.6 million of cash paid for the acquisition of the MGR assets;
- $128.3 million of cash paid for the additional Chipeta interest;
- $107.6 million of cash paid for capital contributions to TEP for construction costs and the initial investments in TEG and FRP; and
- $24.7 million of cash paid for equipment purchases from Anadarko.

Financing Activities. 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 our 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 our 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 for general partnership purposes;
- $100.0 million of net proceeds from the additional 2018 Notes offering in March 2014, after underwriting discounts, original issue premium and offering costs, part of which was used to repay a portion of our outstanding borrowings under our RCF;
- $83.2 million of net proceeds from sales of common units under the Continuous Offering Program (as defined and discussed in Registered Securities within this Item 7), 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; and
- $0.4 million of net proceeds from a capital contribution by our general partner after common units were issued in conjunction with the acquisition of the TEFR Interests.

Net contributions from Anadarko attributable to intercompany balances were $23.8 million during the year ended December 31, 2014, representing intercompany transactions attributable to the acquisition of the TEFR Interests.

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Net cash provided by financing activities for the year ended December 31, 2013, included the following:

- $424.7 million of net proceeds from our May 2013 equity offering, including net proceeds from a capital contribution by our general partner, $245.0 million of which was used to repay a portion of our outstanding borrowings under our RCF;
- $299.0 million of borrowings to fund capital expenditures;
- $273.7 million of net proceeds from our December 2013 equity offering, including net proceeds from a capital contribution by our general partner, $215.0 million of which was used to repay a portion of our outstanding borrowings under our RCF;
- $250.0 million of borrowings to fund the Non-Operated Marcellus Interest acquisition;
- $247.6 million of net proceeds from our 2018 Notes offering in August 2013, after underwriting and original issue discounts and offering costs, all of which was used to repay a portion of our outstanding borrowings under our RCF;
- $133.5 million of borrowings to fund the Anadarko-Operated Marcellus Interest acquisition;
- $41.8 million of net proceeds from sales of common units under the Continuous Offering Program (as defined and discussed in Registered Securities within this Item 7), including net proceeds from capital contributions by our general partner;
- $27.5 million of borrowings to fund the OTTCO acquisition; and
- $0.5 million of net proceeds from a capital contribution by our general partner after common units were issued in conjunction with the Non-Operated Marcellus Interest acquisition.

Net contributions from Anadarko attributable to intercompany balances were $209.0 million during the year ended December 31, 2013, representing intercompany transactions attributable to the acquisitions of the TEFR Interests and the Non-Operated Marcellus Interest.

Net cash provided by financing activities for the year ended December 31, 2012, included the following:

- $511.3 million and $156.4 million of net proceeds from our 2022 Notes offerings in June 2012 and October 2012, respectively, after underwriting and original issue discounts, original issue premiums and offering costs;
- $409.4 million of net proceeds from the issuance of common and general partner units sold in connection with the closing of the WGP IPO;
- $299.0 million of borrowings to fund the acquisition of the MGR assets; and
- $216.4 million of net proceeds from our June 2012 equity offering.

Proceeds from our 2022 Notes offerings were used to repay amounts outstanding under our RCF and our note payable to Anadarko. Net contributions from Anadarko attributable to intercompany balances were $278.6 million during the year ended December 31, 2012, representing intercompany transactions attributable to the acquisitions of the TEFR Interests, the Non-Operated Marcellus Interest and the MGR assets, and the compensation expense allocated to us since the inception of the Incentive Plan.

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For the years ended December 31, 2014, 2013 and 2012, we paid $408.6 million, $299.1 million and $197.9 million, respectively, of cash distributions to our unitholders. Contributions from the noncontrolling interest owners of Chipeta totaled zero, $2.2 million and $29.1 million during the years ended December 31, 2014, 2013 and 2012, respectively, primarily for expansion of the cryogenic units and plant construction. Distributions to the noncontrolling interest owners of Chipeta totaled $15.1 million, $13.1 million and $17.3 million for the years ended December 31, 2014, 2013 and 2012, respectively, representing the distributions paid as of December 31 of the respective year. Decreases in contributions by and distributions to noncontrolling interest owners of Chipeta were also impacted by the August 2012 acquisition of the additional Chipeta interest.

Debt and credit facility. At December 31, 2014, our debt consisted of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the “2021 Notes”), $670.0 million aggregate principal amount of 4.000% Senior Notes due 2022 (the “2022 Notes”), $350.0 million aggregate principal amount of 2.600% Senior Notes due 2018 (the “2018 Notes”), $400.0 million aggregate principal amount of 5.450% Senior Notes due 2044 (the “2044 Notes”), and $510.0 million of borrowings outstanding under our RCF. The two tranches of the 2022 Notes, issued in June and October 2012, were issued under the same indenture and are considered a single class of securities. The two tranches of the 2018 Notes, issued in August 2013 and March 2014, were issued under the same indenture and are considered a single class of securities. As of December 31, 2014, the carrying value of our outstanding debt consisted of $495.7 million of 2021 Notes, $672.9 million of 2022 Notes, $350.5 million of 2018 Notes, $393.8 million of 2044 Notes and $510.0 million of borrowings under the RCF. See Note 12—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Senior Notes. The 2044 Notes issued in March 2014 were offered at a price to the public of 98.443% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2044 Notes is 5.633%. Interest is paid semi-annually on April 1 and October 1 of each year. Proceeds (net of underwriting discount of $3.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under our RCF and for general partnership purposes.

The 2018 Notes issued in March 2014 were offered at a price to the public of 100.857% of the face amount. Including the effects of the issuance premium for the March 2014 offering, the issuance discount for the August 2013 offering of 2018 Notes and underwriting discounts, the effective interest rate of the 2018 Notes is 2.743%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $0.6 million, original issue premium and debt issuance costs) were used to repay amounts then outstanding under our RCF and for general partnership purposes.

At December 31, 2014, we were in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, 2018 Notes, and 2044 Notes.

Revolving credit facility. In February 2014, we entered into an amended and restated $1.2 billion senior unsecured RCF, which is expandable to a maximum of $1.5 billion, replacing an $800.0 million credit facility, which was originally entered into in March 2011. Subsequent to February 2014, we borrowed $350.0 million under the RCF to fund the acquisition of the TEFR Interests (see Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). The RCF matures in February 2019 and bears interest at London Interbank Offered Rate (“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. As of December 31, 2014, we had $510.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $677.2 million available for borrowing under the RCF. The interest rate on the RCF was 1.47% at December 31, 2014. At December 31, 2013, the interest rate on the previous credit facility was 1.67%. 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. The facility fee rate was 0.20% and 0.25% at December 31, 2014 and 2013, respectively. At December 31, 2014, we were in compliance with all covenants under the RCF.

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The RCF continues to contain 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, 2014, we were in compliance with all remaining covenants under the RCF.

The 2021 Notes, 2022 Notes, 2018 Notes, 2044 Notes and obligations under the RCF are recourse to our general partner. Our general partner is indemnified by a wholly owned subsidiary of Anadarko, Western Gas Resources, Inc. ("WGRI") against any claims made against our general partner under the 2022 Notes, 2021 Notes and/or the RCF.

In connection with the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests, our general partner and other wholly owned subsidiaries of Anadarko entered into indemnification agreements, whereby such subsidiaries agreed to indemnify our general partner for any recourse liability it may have for RCF borrowings, or other debt financing, attributable to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests. These indemnification agreements apply to the 2044 Notes, 2018 Notes and/or RCF borrowings outstanding related to the aforementioned acquisitions.

Our general partner, the other indemnifying subsidiaries of Anadarko and WGRI also amended and restated the indemnity agreements between them to (i) conform language among all the indemnification agreements and (ii) reduce the amount for which WGRI would indemnify our general partner by an amount equal to any amounts payable to the general partner under the indemnification agreements related to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests.

Registered securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statements on file with the U.S. Securities and Exchange Commission ("SEC").

In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $125.0 million of common units (the "Continuous Offering Program"), in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. See Note 4—Equity and Partners' Capital in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for a discussion of trades completed under the Continuous Offering Program. As of December 31, 2014, we had used all the capacity to issue common units under this registration statement.

In August 2014, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $500.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings. As of December 31, 2014, we had not issued any common units under such registration statement.

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Credit risk. We bear credit risk represented by our exposure to non-payment or non-performance by our counterparties, including Anadarko, financial institutions, customers and other parties. Generally, non-payment or non-performance results from a customer's inability to satisfy payables to us for services rendered or volumes owed pursuant to gas imbalance agreements. We examine and monitor the creditworthiness of third-party customers and may establish credit limits for third-party customers. A substantial portion of our throughput, however, comes from producers that have investment-grade ratings.

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

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko, which was issued concurrently with the closing of our IPO. We are also party to agreements with Anadarko under which Anadarko is required to indemnify us for certain environmental claims, losses arising from rights-of-way claims, failures to obtain required consents or governmental permits and income taxes with respect to the assets acquired from Anadarko. Finally, we have entered into various commodity price swap agreements with Anadarko in order to reduce our exposure to a substantial majority of the commodity price risk and are subject to performance risk thereunder. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under 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.

CONTRACTUAL OBLIGATIONS

The following is a summary of our contractual cash obligations as of December 31, 2014. 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 2015.

	Obligations by Period						
thousands	2015	2016	2017	2018	2019	Thereafter	Total
Long-term debt							
Principal	$—	$—	$—	$350,000	$510,000	$1,570,000	$2,430,000
Interest	90,911	90,911	90,911	86,686	76,705	654,169	1,090,293
Asset retirement obligations	1,212	1,865	—	—	1,342	104,673	109,092
Capital expenditures	64,084	—	—	—	—	—	64,084
Credit facility fees	2,400	560	—	—	—	—	2,960
Environmental obligations	475	476	476	116	116	315	1,974
Operating leases	338	303	157	34	—	—	832
Total	$159,420	$94,115	$91,544	$436,836	$588,163	$2,329,157	$3,699,235

Debt and 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 Item 8 of this Form 10-K.

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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 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 Item 8 of this Form 10-K.

Environmental obligations. We are subject to various environmental-remediation obligations arising from federal, state and local 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 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 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 Item 8 of this Form 10-K.

CRITICAL ACCOUNTING POLICIES AND 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 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 23 years. If the depreciable lives of our assets were reduced by 10%, we estimate that annual depreciation expense would increase by $24.0 million, which would result in a corresponding reduction in our operating income.

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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.

During 2014, we recognized impairments of $3.1 million, primarily related to a non-operational plant in the Powder River Basin that was impaired to its estimated fair value of $2.4 million, using Level 3 fair-value inputs, the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems and a compressor no longer in service at the Hilight system.

During 2013, we recognized a $1.2 million impairment primarily related to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems.

During 2012, we recognized a $6.0 million impairment related to a gathering system in central Wyoming that was impaired to its estimated fair value using Level 3 fair-value inputs. Also during 2012, an impairment of $0.6 million was recognized for the original installation costs on a compressor relocated within our operating assets.

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 (2) transportation. The carrying value of goodwill as of December 31, 2014, was $379.6 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. In connection with the November 2014 DBM acquisition, we recorded $279.1 million of goodwill. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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The first step in assessing whether an impairment of goodwill is necessary is an optional qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is greater than its carrying amount. If we conclude that the fair value of the reporting unit more than likely exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment is not performed or 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. In this manner, estimating the fair value of our reporting units was not necessary based on the qualitative evaluation as of October 1, 2014. 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.

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 earnings before interest, taxes, depreciation, and amortization (“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, 2014 and 2013, 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 Note 8—Goodwill and Intangibles in the Notes to Consolidated Financial Statements under 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.

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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 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 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.

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 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 Item 8 of this Form 10-K.

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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. 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 utilized.

To mitigate our exposure to a substantial majority of the changes in commodity prices as a result of the purchase and sale of natural gas, condensate or NGLs, we currently have in place commodity price swap agreements with Anadarko expiring at various times through December 2016. On December 31, 2014, our commodity price swap agreements for the Hilight and Newcastle systems and the Granger complex expired without renewal. On June 30, 2015, and September 30, 2015, our commodity price swap agreements for the DJ Basin complex and Hugoton system, respectively, will expire. See Risk Factors under Item 1A and Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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

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

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

Interest rate risk. Interest rates during the year ended December 31, 2014, were low compared to historic rates. As of December 31, 2014, we had $510.0 million of outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). If interest rates rise, our future financing costs could increase. A 10% change in LIBOR would have resulted in a nominal change in net income and the fair value of the borrowings under the RCF at December 31, 2014.

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.

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 the Partnership's 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. 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 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 to the Partnership's Management and Directors regarding the preparation and fair presentation of published 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.

Management assessed the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014. 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, we believe that as of December 31, 2014, the Partnership's internal control over financial reporting was effective based on those criteria. The Partnership acquired Nuevo Midstream, LLC in November 2014 and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014, Nuevo Midstream, LLC's internal control over financial reporting associated with total assets of $1.6 billion and total revenues of $12.5 million included in the consolidated financial statements of Western Gas Partners, LP and subsidiaries as of and for the year ended December 31, 2014.

KPMG LLP has issued an attestation report on the Partnership's internal control over financial reporting as of December 31, 2014.

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

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

February 26, 2015

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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, 2014, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership'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, 2014, 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 acquired Nuevo Midstream, LLC in November 2014, and management excluded from its assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2014, Nuevo Midstream, LLC's internal control over financial reporting associated with total assets of $1.6 billion and total revenues of $12.5 million included in the consolidated financial statements of the Partnership and subsidiaries as of and for the year ended December 31, 2014. Our audit of internal control over financial reporting of the Partnership also excluded an evaluation of the internal control over financial reporting of Nuevo Midstream, LLC.

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, 2014 and 2013, and the related consolidated statements of income, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 26, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Houston, Texas
February 26, 2015

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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, 2014 and 2013, and the related consolidated statements of income, equity and partners' capital, and cash flows for each of the years in the three-year period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, 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, 2014, 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 26, 2015 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP
Houston, Texas
February 26, 2015

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
thousands except per-unit amounts	2014	2013	2012
Revenues – affiliates			
Gathering, processing and transportation of natural gas and natural gas liquids	$394,870	$306,810	$249,997
Natural gas, natural gas liquids and condensate sales	570,047	496,848	436,423
Other	5,078	1,868	1,606
Total revenues – affiliates	969,995	805,526	688,026
Revenues – third parties			
Gathering, processing and transportation of natural gas and natural gas liquids	252,581	175,732	132,333
Natural gas, natural gas liquids and condensate sales	42,807	44,396	71,916
Other	8,380	4,109	2,201
Total revenues – third parties	303,768	224,237	206,450
Total revenues	1,273,763	1,029,763	894,476
Equity income, net [1]	57,836	22,948	16,042
Operating expenses			
Cost of product [2]	437,956	364,285	336,079
Operation and maintenance [2]	199,305	168,657	140,106
General and administrative [2]	34,242	29,751	99,212
Property and other taxes	25,353	23,244	19,688
Depreciation, amortization and impairments	183,156	145,916	120,608
Total operating expenses	880,012	731,853	715,693
Operating income	451,587	320,858	194,825
Interest income – affiliates	16,900	16,900	16,900
Interest expense [3]	(76,766)	(51,797)	(42,060)
Other income (expense), net	864	1,837	292
Income before income taxes	392,585	287,798	169,957
Income tax (benefit) expense	2,027	2,355	20,690
Net income	390,558	285,443	149,267
Net income attributable to noncontrolling interests	14,025	10,816	14,890
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Limited partners' interest in net income:			
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Pre-acquisition net (income) loss allocated to Anadarko	956	(4,128)	(27,391)
General partner interest in net (income) loss [4]	(120,980)	(69,633)	(28,089)
Limited partners' interest in net income [4]	256,509	200,866	78,897
Net income per common unit – basic [5]	$2.13	$1.83	$0.84
Net income per common unit – diluted [5]	2.12	1.83	0.84

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

(2) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $114.0 million, $129.0 million and $145.3 million for the years ended December 31, 2014, 2013 and 2012, respectively. Operation and maintenance includes charges from Anadarko of $58.9 million, $56.4 million and $51.2 million for the years ended December 31, 2014, 2013 and 2012, respectively. General and administrative includes charges from Anadarko of $27.0 million, $23.4 million and $92.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. See Note 5.

(3)

Includes affiliate (as defined in Note 1) interest expense of zero for each of the years ended December 31, 2014 and 2013, and $2.8 million for the year ended December 31, 2012. See Note 12.

(4) Represents net income 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 per unit.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31,	
thousands except number of units	2014	2013
ASSETS		
Current assets		
Cash and cash equivalents	$67,054	$100,728
Accounts receivable, net [(1)]	98,114	84,060
Other current assets [(2)]	10,067	10,022
Total current assets	175,235	194,810
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	5,424,699	4,239,100
Less accumulated depreciation	1,040,328	855,845
Net property, plant and equipment	4,384,371	3,383,255
Goodwill	384,387	105,336
Other intangible assets	884,857	53,606
Equity investments	634,492	593,400
Other assets	28,289	27,401
Total assets	$6,751,631	$4,617,808
LIABILITIES, EQUITY AND PARTNERS’ CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [(3)]	$29,104	$39,589
Accrued ad valorem taxes	14,812	13,860
Accrued liabilities [(4)]	158,655	137,011
Total current liabilities	202,571	190,460
Long-term debt	2,422,954	1,418,169
Deferred income taxes	4,171	37,998
Asset retirement obligations and other	110,069	79,145
Total long-term liabilities	2,537,194	1,535,312
Total liabilities	2,739,765	1,725,772
Equity and partners’ capital		
Common units (127,695,130 and 117,322,812 units issued and outstanding at December 31, 2014 and 2013, respectively)	3,119,714	2,431,193
Class C units (10,913,853 and zero units issued and outstanding at December 31, 2014 and 2013, respectively)	716,957	—
General partner units (2,583,068 and 2,394,345 units issued and outstanding at December 31, 2014 and 2013, respectively)	105,725	78,157
Net investment by Anadarko	—	312,092
Total partners’ capital	3,942,396	2,821,442
Noncontrolling interest	69,470	70,594
Total equity and partners’ capital	4,011,866	2,892,036
Total liabilities, equity and partners’ capital	$6,751,631	$4,617,808

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $64.7 million and $47.9 million as of December 31, 2014 and 2013, respectively.

(2) Other current assets includes natural gas imbalance receivables from affiliates of $0.2 million and $0.1 million as of December 31, 2014 and 2013, respectively.

(3)

Accounts and natural gas imbalance payables includes amounts payable to affiliates of $0.1 million and $2.3 million as of December 31, 2014 and 2013, respectively.

(4) Accrued liabilities includes amounts payable to affiliates of zero and $0.1 million as of December 31, 2014 and 2013, respectively.

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	General Partner Units	Noncontrolling Interests	Total
Balance at December 31, 2011	$362,573	$1,495,253	$—	$31,729	$ 120,724	$2,010,279
Net income (loss)	27,391	78,897	—	28,089	14,890	149,267
Issuance of common and general partner units, net of offering expenses	—	613,188	—	12,689	—	625,877
Contributions from noncontrolling interest owners	—	—	—	—	29,108	29,108
Distributions to noncontrolling interest owners	—	—	—	—	(17,303)	(17,303)
Distributions to unitholders	—	(175,639)	—	(22,211)	—	(197,850)
Acquisition from affiliates	(482,701)	23,458	—	479	—	(458,764)
Acquisition of additional 24% interest in Chipeta [(1)]	—	(44,071)	—	162	(77,195)	(121,104)
Contributions of equity-based compensation from Anadarko [(2)]	—	84,971	—	2,086	—	87,057
Net pre-acquisition contributions from (distributions to) Anadarko	299,833	(106,597)	—	—	—	193,236
Net distributions to Anadarko of other assets	—	(15,002)	—	(273)	(21)	(15,296)
Elimination of net deferred tax liabilities	106,504	—	—	—	—	106,504
Other	—	2,608	—	2	455	3,065
Balance at December 31, 2012	$313,600	$1,957,066	$—	$52,752	$ 70,658	$2,394,076
Net income (loss)	4,128	200,866	—	69,633	10,816	285,443
Issuance of common and general partner units, net of offering expenses	—	724,811	—	15,775	—	740,586
Contributions from noncontrolling interest owner	—	—	—	—	2,247	2,247
Distributions to noncontrolling interest owner	—	—	—	—	(13,127)	(13,127)
Distributions to unitholders	—	(239,157)	—	(59,944)	—	(299,101)
Acquisitions from affiliates	(255,635)	(209,865)	—	—	—	(465,500)
Contributions of equity-based compensation from Anadarko [(2)]	—	2,865	—	58	—	2,923
Net pre-acquisition contributions from (distributions to) Anadarko [(3)]	203,469	—	—	—	—	203,469
Net distributions to Anadarko of other assets	—	(5,738)	—	(117)	—	(5,855)
Elimination of net deferred tax liabilities	46,530	—	—	—	—	46,530
Other	—	345	—	—	—	345
Balance at December 31, 2013	$312,092	$2,431,193	$—	$78,157	$ 70,594	$2,892,036

Net income (loss)	(956)	254,737	1,772	120,980	14,025	390,558
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 (2)	—	3,104	—	63	—	3,167
Net pre-acquisition contributions from (distributions to) Anadarko (3)	23,488	—	—	—	—	23,488
Net distributions to Anadarko of other assets	—	(10,519)	—	(214)	—	(10,733)
Elimination of net deferred tax liabilities	38,160	—	—	—	—	38,160
Other	—	482	—	—	—	482
Balance at December 31, 2014	$—	$3,119,714	$716,957	$105,725	$ 69,470	$4,011,866

(1) See Note 2 for a description of the acquisition of Anadarko's then-remaining 24% membership interest in Chipeta in August 2012. The$43.9 million decrease to partners' capital resulting from the August 2012 Chipeta acquisition, together with net income attributable to Western Gas Partners, LP, totaled $90.5 million for the year ended December 31, 2012.

(2) Associated with the Anadarko Incentive Plans for the years ended December 31, 2014, 2013 and 2012 and the Incentive Plan for the year ended December 31, 2012, as defined and described in Note 1 and Note 5.

(3) Includes deferred taxes on capitalized interest of $0.3 million and $5.5 million associated with the acquisition of the TEFR Interests (as defined and described in Note 1) for the years ended December 31, 2014 and 2013, respectively.

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	2014	2013	2012
Cash flows from operating activities			
Net income	$390,558	$285,443	$149,267
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairments	183,156	145,916	120,608
Non-cash equity-based compensation expense	3,920	3,521	3,717
Deferred income taxes	2,583	31,891	30,109
Debt-related amortization and other items, net	2,736	2,449	2,319
Equity income, net [1]	(57,836)	(22,948)	(16,042)
Distributions from equity investment earnings [1]	62,967	17,698	20,660
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	(4,217)	(34,019)	22,916
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	(52,530)	21,952	5,045
Change in other items, net	3,470	(3,702)	(552)
Net cash provided by operating activities	534,807	448,201	338,047
Cash flows from investing activities			
Capital expenditures	(673,004)	(646,471)	(638,121)
Contributions in aid of construction costs from affiliates	183	617	—
Acquisitions from affiliates	(379,193)	(476,711)	(611,719)
Acquisitions from third parties	(1,523,327)	(240,274)	—
Investments in equity affiliates	(64,278)	(294,693)	(108,457)
Distributions from equity investments in excess of cumulative earnings [1]	18,055	4,438	—
Proceeds from the sale of assets to affiliates	—	85	760
Proceeds from the sale of assets to third parties	5	14	—
Net cash used in investing activities	(2,621,559)	(1,652,995)	(1,357,537)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	1,646,878	957,503	1,041,648
Repayments of debt	(650,000)	(710,000)	(549,000)
Increase (decrease) in outstanding checks	1,693	(1,763)	1,800
Proceeds from the issuance of common and general partner units, net of offering expenses	704,489	740,825	625,877
Proceeds from the issuance of Class C units	750,000	—	—
Distributions to unitholders	(408,621)	(299,101)	(197,850)
Contributions from noncontrolling interest owners	—	2,247	29,108
Distributions to noncontrolling interest owners	(15,149)	(13,127)	(17,303)
Net contributions from Anadarko	23,788	208,957	278,632
Net cash provided by financing activities	2,053,078	885,541	1,212,912
Net increase (decrease) in cash and cash equivalents	(33,674)	(319,253)	193,422
Cash and cash equivalents at beginning of period	100,728	419,981	226,559
Cash and cash equivalents at end of period	$67,054	$100,728	$419,981
Supplemental disclosures			
Net distributions to Anadarko of other assets	$10,733	$5,855	$15,296
Interest paid, net of capitalized interest	67,648	47,098	28,042
Taxes paid (reimbursements received)	(90)	552	495

Capital lease asset transfer [2]	4,833	—	—

[1] Income earned on, distributions from and contributions to equity investments are classified as affiliate. See Note 1.
[2] For the year ended December 31, 2014, represents transfers of $4.6 million from other long-term assets, associated with the capital lease components of a processing agreement. See Note 7.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General. Western Gas Partners, LP is a growth-oriented Delaware master limited partnership formed by Anadarko Petroleum Corporation in 2007 to own, operate, acquire and develop midstream energy assets. The Partnership closed its initial public offering ("IPO") to become publicly traded in 2008.
For purposes of these consolidated financial statements, the "Partnership" refers to Western Gas Partners, LP and its subsidiaries. The Partnership's general partner, Western Gas Holdings, LLC (the "general partner" or "GP"), is owned by Western Gas Equity Partners, LP ("WGP"), a Delaware master limited partnership formed by Anadarko Petroleum Corporation in September 2012 to own the Partnership's general partner, as well as a significant limited partner interest in the Partnership (see Western Gas Equity Partners, LP below). Western Gas Equity Holdings, LLC is WGP's general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. "Anadarko" refers to Anadarko Petroleum Corporation and its subsidiaries, excluding the Partnership and the general partner, and "affiliates" refers to subsidiaries of Anadarko, excluding the Partnership, and includes equity interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), Enterprise EF78 LLC (the "Mont Belvieu JV"), Texas Express Pipeline LLC ("TEP"), Texas Express Gathering LLC ("TEG") and Front Range Pipeline LLC ("FRP") (see Note 2). The interests in TEP, TEG and FRP are referred to collectively as the "TEFR Interests." All income earned on, distributions from and contributions to, the Partnership's equity investments are considered to be affiliate transactions. "Equity investment throughput" refers to the Partnership's 14.81% share of average Fort Union throughput and 22% share of average Rendezvous throughput, but excludes throughput measured in barrels, consisting of the Partnership's 10% share of average White Cliffs throughput, 25% share of average Mont Belvieu JV throughput, 20% share of average TEP and TEG throughput and 33.33% share of average FRP throughput. The "DJ Basin complex" refers to the Platte Valley system, Wattenberg system, and Lancaster plant, all of which were combined into a single complex in the first quarter of 2014.
The Partnership is engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko, as well as for third-party producers and customers. As of December 31, 2014, the Partnership's assets and investments accounted for under the equity method consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests	Equity Interests
Natural gas gathering systems	14	1	5	2
Natural gas treating facilities	8	—	—	1
Natural gas processing facilities	13	3	—	2
NGL pipelines	3	—	—	3
Natural gas pipelines	4	—	—	—
Oil pipeline	1	—	—	1

These assets and investments are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), North-central Pennsylvania and Texas. The Partnership is constructing Train II at the Lancaster plant (located at the DJ Basin complex) with operations expected to commence in the second quarter of 2015. In addition, the Partnership is preparing for construction of Train IV at the DBM complex (see Note 2), with operations expected to commence in the first quarter of 2016. The Partnership has also made progress payments towards the construction of another cryogenic unit at the DBM complex (Train V), with an expected in-service date of mid-2016.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Western Gas Equity Partners, LP. In December 2012, WGP completed its IPO of 19,758,150 common units representing limited partner interests in WGP at a price of $22.00 per common unit. WGP used the net proceeds from the offering to purchase common and general partner units of the Partnership resulting in aggregate proceeds to the Partnership of $409.4 million, which was used by the Partnership for general partnership purposes, including the funding of capital expenditures.
WGP owns the following types of interests in the Partnership: (i) the general partner interest and all of the incentive distribution rights ("IDRs") in the Partnership, both owned through WGP's 100% ownership of the Partnership's general partner and (ii) a significant limited partner interest (see Holdings of Partnership equity in Note 4). WGP has no independent operations or material assets other than its partnership interests in the Partnership.

Basis of presentation. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP"). The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest. All significant intercompany transactions have been eliminated. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated financial statements.
Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership proportionately consolidates its 33.75% share of the assets, liabilities, revenues and expenses attributable to the Non-Operated Marcellus Interest systems and Anadarko-Operated Marcellus Interest systems (see Note 2) and its 50% share of the assets, liabilities, revenues and expenses attributable to the Newcastle system in the accompanying consolidated financial statements.
In July 2009, the Partnership acquired a 51% interest in Chipeta Processing LLC ("Chipeta") and became party to Chipeta's limited liability company agreement (the "Chipeta LLC agreement"). On August 1, 2012, the Partnership acquired Anadarko's then-remaining 24% membership interest in Chipeta (the "additional Chipeta interest"). Prior to this transaction, the interests in Chipeta held by Anadarko and a third-party member were reflected as noncontrolling interests in the consolidated financial statements. The acquisition of the additional Chipeta interest was accounted for on a prospective basis as the Partnership acquired an additional interest in an already-consolidated entity. As such, effective August 1, 2012, noncontrolling interest excludes the financial results and operations of the additional Chipeta interest. The remaining 25% membership interest held by the third-party member is reflected within noncontrolling interests in the consolidated financial statements for all periods presented. See Note 2.

Presentation of Partnership assets. The term "Partnership assets" refers to the assets owned and interests accounted for under the equity method (see Note 9) by the Partnership as of December 31, 2014. Because Anadarko controls the Partnership through its ownership and control of WGP, which owns the Partnership's entire general partner interest, each acquisition of Partnership assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by the Partnership (see Note 2). Further, after an acquisition of Partnership assets from Anadarko, the Partnership may be required to recast its financial statements to include the activities of such Partnership assets from the date of common control.
For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership's acquisition of the Partnership assets from Anadarko have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the Partnership assets during the periods reported. Net income attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Use of estimates. In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, using historical experience and other methods considered reasonable under the particular circumstances. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revisions become known.

Fair value. The fair-value-measurement standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

Level 1 – Inputs represent quoted prices in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3 – Inputs that are not observable from objective sources, such as management’s internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in management’s internally developed present value of future cash flows model that underlies the fair value measurement).

Nonfinancial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a third-party business combination, assets and liabilities exchanged in non-monetary transactions, long-lived assets (asset groups), goodwill and other intangibles, initial recognition of asset retirement obligations, and initial recognition of environmental obligations assumed in a third-party acquisition. Impairment analyses for long-lived assets, goodwill and other intangibles, and the initial recognition of asset retirement obligations and environmental obligations use Level 3 inputs. When the Partnership 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, the Partnership uses the cost, income, or market valuation approach depending on the quality of information available to support management’s assumptions.
The fair value of debt reflects any premium or discount for the difference between the stated interest rate and the quarter-end market interest rate, and is based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments. See Note 12.
The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable reported on the consolidated balance sheets approximate fair value due to the short-term nature of these items.

Cash equivalents. The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Bad-debt reserve. The Partnership’s revenues are primarily from Anadarko, for which no credit limit is maintained. The Partnership analyzes its exposure to bad debts on a customer-by-customer basis for its third-party accounts receivable and may establish credit limits for significant third-party customers. As of December 31, 2014 and 2013, the Partnership’s bad-debt reserve was immaterial.

Natural gas imbalances. The consolidated balance sheets include natural gas imbalance receivables and payables resulting from differences in gas volumes received into the Partnership’s systems and gas volumes delivered by the Partnership to customers’ pipelines. Natural gas volumes owed to or by the Partnership that are subject to monthly cash settlement are valued according to the terms of the contract as of the balance sheet dates and reflect market index prices. Other natural gas volumes owed to or by the Partnership are valued at the Partnership’s weighted-average cost of natural gas as of the balance sheet dates and are settled in-kind. As of December 31, 2014, natural gas imbalance receivables and payables were $0.4 million and $0.7 million, respectively. As of December 31, 2013, natural gas imbalance receivables and payables were $3.6 million and $2.5 million, respectively. Changes in natural gas imbalances are reported in other revenues for imbalance receivables or in cost of product for imbalance payables.

Inventory. The cost of NGLs inventories is determined by the weighted-average cost method on a location-by-location basis. Inventory is stated at the lower of weighted-average cost or market value and is reported in other current assets in the consolidated balance sheets. See Note 10.

Property, plant and equipment. 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 assets acquired from Anadarko are initially recorded at Anadarko’s historic carrying value. The difference between the carrying value of net assets acquired from Anadarko and the consideration paid is recorded as an adjustment to partners’ capital.

Assets acquired in a business combination or non-monetary exchange with a third party are initially recorded at fair value. All construction-related direct labor and material costs are capitalized. The cost of renewals and betterments that extend the useful life of property, plant and equipment is also capitalized. The cost of repairs, replacements and major maintenance projects that do not extend the useful life or increase the expected output of property, plant and equipment is expensed as incurred.

Depreciation is computed using the straight-line method based on estimated useful lives and salvage values of assets. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts. Uncertainties that may impact these estimates include, but are not limited to, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions, and supply and demand in the area.

Management evaluates the ability to recover the carrying amount of its long-lived assets to determine whether its long-lived assets have been impaired. 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. Refer to Note 7 for a description of impairments recorded during the years ended December 31, 2014, 2013 and 2012.

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Capitalized interest. Interest is capitalized as part of the historical cost of constructing assets for significant projects that are in progress. Capitalized interest is determined by multiplying the Partnership's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once the construction of an asset subject to interest capitalization is completed and the asset is placed in service, the associated capitalized interest is expensed through depreciation or impairment, together with other capitalized costs related to that asset.

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. Refer to Note 8 for a discussion of goodwill. The Partnership evaluates goodwill for impairment annually, as of October 1, or more often as facts and circumstances warrant. The Partnership has allocated goodwill on its two reporting units: (i) gathering and processing and (ii) transportation. An initial qualitative assessment may be performed prior to proceeding to the comparison of the fair value of each reporting unit to which goodwill has been assigned, to the carrying amount of net assets, including goodwill, of each reporting unit. If the Partnership concludes, based on qualitative factors, that it is more likely than not that the fair value of the reporting unit exceeds its carrying amount, then goodwill is not impaired, and estimating the fair value of the reporting unit is not necessary. If the carrying amount of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value through a charge to operating expense based on a hypothetical purchase price allocation. The carrying value of goodwill after such an impairment would represent a Level 3 fair value measurement.

Other intangible assets. The Partnership assesses intangible assets, as described in Note 8, for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See Property, plant and equipment within this Note 1 for further discussion of management's process to evaluate potential impairment of long-lived assets.

Asset retirement obligations. Management recognizes a liability based on the estimated costs of retiring tangible long-lived assets. The liability is recognized at fair value, measured using discounted expected future cash outflows for the asset retirement obligation when the obligation originates, which generally is when an asset is acquired or constructed. The carrying amount of the associated asset is increased commensurate with the liability recognized. Over time, the discounted liability is adjusted to its expected settlement value through accretion expense, which is reported within depreciation, amortization and impairments in the consolidated statements of income. Subsequent to the initial recognition, the liability is also adjusted for any changes in the expected value of the retirement obligation (with a corresponding adjustment to property, plant and equipment) until the obligation is settled. Revisions in estimated asset retirement obligations may result from changes in estimated inflation rates, discount rates, asset retirement costs and the estimated timing of settling asset retirement obligations. See Note 11.

Environmental expenditures. The Partnership expenses environmental obligations related to conditions caused by past operations that do not generate current or future revenues. Environmental obligations related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation or other potential environmental liabilities becomes probable and the costs can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations are recognized no later than at the time of the completion of the remediation feasibility study. These accruals are adjusted as additional information becomes available or as circumstances change. Costs of future expenditures for environmental-remediation obligations are not discounted to their present value. See Note 13.

Segments. The Partnership's operations are organized into a single operating segment, the assets of which gather, process, compress, treat and transport Anadarko and third-party natural gas, condensate, NGLs and crude oil in the United States.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Revenues and cost of product. Under its fee-based gathering, treating and processing arrangements, the Partnership is paid a fixed fee based on the volume and thermal content of natural gas and recognizes revenues for its services in the month such services are performed. Producers' wells are connected to the Partnership's gathering systems for delivery of natural gas to the Partnership's processing or treating plants, where the natural gas is processed to extract NGLs and condensate or treated in order to satisfy pipeline specifications. In some areas, where no processing is required, the producers' gas is gathered and delivered to pipelines for market delivery. Under cost-of-service gathering agreements, the Partnership earns fees for gathering and compression services based on rates calculated in a cost-of-service model and reviewed periodically over the life of the agreements. Under percent-of-proceeds contracts, revenue is recognized when the natural gas, NGLs or condensate are sold. The percentage of the product sale ultimately paid to the producer is recorded as a related cost of product expense.

The Partnership purchases natural gas volumes at the wellhead for gathering and processing. As a result, the Partnership has volumes of NGLs and condensate to sell and volumes of residue to either sell, to use for system fuel or to satisfy keep-whole obligations. In addition, depending upon specific contract terms, condensate and NGLs recovered during gathering and processing are either returned to the producer or retained and sold. Under keep-whole contracts, when condensate or NGLs are retained and sold, producers are kept whole for the condensate or NGL volumes through the receipt of a thermally equivalent volume of residue. The keep-whole contract conveys an economic benefit to the Partnership when the combined value of the individual NGLs is greater in the form of liquids than as a component of the natural gas stream; however, the Partnership is adversely impacted when the value of the NGLs is lower than the value of the natural gas stream including the liquids. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to a substantial majority of the commodity price uncertainty that would otherwise be present as a result of the purchase and sale of natural gas, condensate or NGLs. See Note 5. Revenue is recognized from the sale of condensate and NGLs upon transfer of title and related purchases are recorded as cost of product.

The Partnership earns transportation revenues through firm contracts that obligate each of its customers to pay a monthly reservation or demand charge regardless of the pipeline capacity used by that customer. An additional commodity usage fee is charged to the customer based on the actual volume of natural gas transported. Transportation revenues are also generated from interruptible contracts pursuant to which a fee is charged to the customer based on volumes transported through the pipeline. Revenues for transportation of natural gas and NGLs are recognized over the period of firm transportation contracts or, in the case of usage fees and interruptible contracts, when the volumes are received into the pipeline. From time to time, certain revenues may be subject to refund pending the outcome of rate matters before the Federal Energy Regulatory Commission (the "FERC") and reserves are established where appropriate.

Proceeds from the sale of residue, NGLs and condensate are reported as revenues from natural gas, natural gas liquids and condensate sales in the consolidated statements of income. Revenues attributable to the fixed-fee component of gathering and processing contracts as well as demand charges and commodity usage fees on transportation contracts are reported as revenues from gathering, processing and transportation of natural gas and natural gas liquids in the consolidated statements of income.

Equity-based compensation. Phantom unit awards are granted under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the "WES LTIP"). The WES LTIP was adopted by the general partner of the Partnership and permits the issuance of up to 2,250,000 units, of which 2,133,227 units remained available for future issuance as of December 31, 2014. Upon vesting of each phantom unit awarded under the WES LTIP, the holder will receive common units of the Partnership or, at the discretion of the general partner's Board of Directors, cash in an amount equal to the market value of common units of the Partnership on the vesting date. Equity-based compensation expense attributable to grants made under the WES LTIP impact the Partnership's cash flows from operating activities only to the extent cash payments are made to a participant in lieu of issuance of common units to the participant. The Partnership amortizes stock-based compensation expense attributable to awards granted under the WES LTIP over the vesting periods applicable to the awards.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Additionally, the Partnership's general and administrative expenses include equity-based compensation costs allocated by Anadarko to the Partnership for grants made pursuant to (i) the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan (the "WGP LTIP") for the years ended December 31, 2014 and 2013, (ii) the Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated (the "Incentive Plan") for the year ended December 31, 2012, and (iii) the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 and 2012 Omnibus Incentive Compensation Plans (Anadarko's plans are referred to collectively as the "Anadarko Incentive Plans") for all periods presented. Grants made under equity-based compensation plans result in equity-based compensation expense, which is determined by reference to the fair value of equity compensation. For equity-based awards ultimately settled through the issuance of units or stock, the fair value is measured as of the date of the relevant equity grant. Equity-based compensation granted under the WGP LTIP and the Anadarko Incentive Plans does not impact the Partnership's cash flows from operating activities since the offset to compensation expense is recorded as a contribution to partners' capital in the consolidated financial statements at the time of contribution, when the expense is realized. However, distribution equivalent rights awarded in tandem with equity-or liability-based awards are paid in cash and reflected within financing cash flows in the consolidated statements of cash flows. See Note 5.

Income taxes. The Partnership generally is not subject to federal income tax or state income tax other than Texas margin tax on the portion of its income that is apportionable to Texas. Deferred state income taxes are recorded on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. The Partnership routinely assesses the realizability of its deferred tax assets. If the Partnership concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. Federal and state current and deferred income tax expense was recorded on the Partnership assets prior to the Partnership's acquisition of these assets from Anadarko.

For periods beginning on and subsequent to the Partnership's acquisition of the Partnership assets, the Partnership makes payments to Anadarko pursuant to the tax sharing agreement entered into between Anadarko and the Partnership for its estimated share of taxes from all forms of taxation, excluding taxes imposed by the United States, that are included in any combined or consolidated returns filed by Anadarko. The aggregate difference in the basis of the Partnership's assets for financial and tax reporting purposes cannot be readily determined as the Partnership does not have access to information about each partner's tax attributes in the Partnership.

The accounting standards for uncertain tax positions defines the criteria an individual tax position must satisfy for any part of the benefit of that position to be recognized in the financial statements. The Partnership had no material uncertain tax positions at December 31, 2014 or 2013.

With respect to assets acquired from Anadarko, the Partnership recorded Anadarko's historic current and deferred income taxes for the periods prior to the Partnership's ownership of the assets. For periods subsequent to the Partnership's acquisition, the Partnership is not subject to tax except for the Texas margin tax and, accordingly, does not record current and deferred federal income taxes related to the assets acquired from Anadarko.

Net income per common unit. The Partnership applies the two-class method in determining net income per unit applicable to master limited partnerships having multiple classes of securities including common units, Class C units, general partner units and IDRs. The two-class method is an earnings allocation formula that treats participating securities as having rights to earnings that otherwise would have been available to common unitholders. Under the two-class method, net income per unit is calculated as if all of the earnings for the period were distributed pursuant to the terms of the relevant contractual arrangement. The accounting guidance provides the methodology for and circumstances under which undistributed earnings are allocated to the general partner, limited partners and IDR holders. For the Partnership, earnings per unit is calculated based on the assumption that the Partnership distributes to its unitholders an amount of cash equal to the net income of the Partnership, notwithstanding the general partner’s ultimate discretion over the amount of cash to be distributed for the period, the existence of other legal or contractual limitations that would prevent distributions of all of the net income for the period or any other economic or practical limitation on the ability to make a full distribution of all of the net income for the period.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The Partnership's net income earned on and subsequent to the date of the acquisition of the Partnership assets is allocated to the general partner and the limited partners, including any Class C unitholders, in accordance with their respective weighted-average ownership percentages and, when applicable, giving effect to incentive distributions allocable to the general partner. The Partnership's net income allocable to the limited partners is allocated between the common and Class C unitholders by applying the provisions of the partnership agreement that govern actual cash distributions and capital account allocations, as if all earnings for the period had been distributed (see discussion of Class C beneficial conversion feature and related impacts on earnings per unit in Note 4). Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner, common and Class C unitholders consistent with actual cash distributions and capital account allocations, including incentive distributions allocable to the general partner. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner, common unitholders and Class C unitholders in accordance with their respective weighted-average ownership percentages during each period. Net income attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of the Partnership assets is not allocated to the limited partners for purposes of calculating net income per common and Class C unit. See Note 4.

Contributions in aid of construction costs from affiliates. On certain of the Partnership's capital projects, Anadarko is obligated to reimburse the Partnership for all or a portion of project capital expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. These cash receipts are presented as "Contributions in aid of construction costs from affiliates" within the investing section of the Partnership's consolidated statements of cash flows. See Note 5.

Recently issued accounting standards. Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers, supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and industry-specific guidance in Subtopic 932-605, Extractive Activities—Oil and Gas—Revenue Recognition, and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU is effective for annual and interim periods beginning in 2017 and is required to be adopted using one of two retrospective application methods, with no early adoption permitted. The Partnership is currently evaluating the impact of the adoption of this ASU on its consolidated financial statements.
ASU 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity, changes the criteria for reporting discontinued operations and requires additional disclosures, both for discontinued operations and for individually significant dispositions and assets classified as held for sale not qualifying as discontinued operations. This ASU is effective for annual and interim periods beginning in 2015, with early adoption permitted for disposals or for assets classified as held for sale that have not been reported in previously issued financial statements. The Partnership early adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on the Partnership's consolidated financial statements.
ASU 2013-11, Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, requires that an unrecognized tax benefit, or a portion of an unrecognized tax benefit, be presented in the financial statements as a reduction to a deferred tax asset, except in certain circumstances. This ASU is effective for annual and interim periods beginning in 2014. The Partnership adopted this ASU on a prospective basis beginning with the first quarter of 2014. The adoption did not have a material impact on the Partnership's consolidated financial statements. See Note 6—Income Taxes.

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2. ACQUISITIONS

In May 2008, concurrently with the closing of the Partnership's IPO, Anadarko contributed to the Partnership the assets and liabilities of Anadarko Gathering Company LLC, Pinnacle Gas Treating LLC, and MIGC LLC. In December 2008, the Partnership completed the acquisition of the Powder River assets from Anadarko, which included (i) the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% membership interest in Fort Union. In July 2009, the Partnership closed on the acquisition of a 51% membership interest in Chipeta from Anadarko. The Partnership closed the acquisitions of Anadarko's Granger and Wattenberg assets in January 2010 and August 2010, respectively. In September 2010, the Partnership acquired a 10% interest in White Cliffs. The Partnership closed the acquisition of the Platte Valley assets from a third party in February 2011 and the acquisition of the Bison assets from Anadarko in July 2011.
The following table presents the acquisitions completed by the Partnership during the years ended December 31, 2014, 2013 and 2012, and identifies the funding sources for such acquisitions:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired		Borrowings	Cash On Hand	Common Units Issued to Anadarko	Class C Units Issued to Anadarko	GP Units Issued
MGR (1)	01/13/2012	100	%	$299,000	$159,587	632,783	—	12,914
Chipeta (2)	08/01/2012	24	%	—	128,250	151,235	—	3,086
Non-Operated Marcellus Interest (3)	03/01/2013	33.75	%	250,000	215,500	449,129	—	—
Anadarko-Operated Marcellus Interest (4)	03/08/2013	33.75	%	133,500	—	—	—	—
Mont Belvieu JV (5)	06/05/2013	25	%	—	78,129	—	—	—
OTTCO (6)	09/03/2013	100	%	27,500	—	—	—	—
TEFR Interests (7)	03/03/2014	Various (7)		350,000	6,250	308,490	—	—
DBM (8)	11/25/2014	100	%	475,000	298,327	—	10,913,853	—

(1) The assets acquired from Anadarko consisted of (i) the "Red Desert complex," which is located in the greater Green River Basin in southwestern Wyoming, and includes the Patrick Draw processing plant, the Red Desert processing plant, gathering lines, and related facilities, (ii) a 22% interest in Rendezvous, which owns a gathering system serving the Jonah and Pinedale Anticline fields in southwestern Wyoming, and (iii) certain additional midstream assets and equipment. These assets are collectively referred to as the "MGR assets" and the acquisition as the "MGR acquisition."

(2) The Partnership acquired Anadarko's additional Chipeta interest (as described in Note 1). The Partnership received distributions related to the additional interest beginning July 1, 2012. This transaction brought the Partnership's total membership interest in Chipeta to 75%. The remaining 25% membership interest in Chipeta held by a third-party member is reflected as noncontrolling interests in the consolidated financial statements for all periods presented.

(3) The Partnership acquired Anadarko's 33.75% interest (non-operated) (the "Non-Operated Marcellus Interest") in the Liberty and Rome gas gathering systems (the "Non-Operated Marcellus Interest systems"), serving production from the Marcellus shale in North-central Pennsylvania. In connection with the issuance of the common units, the Partnership's general partner purchased 9,166 general partner units for consideration of $0.5 million.

(4) The Partnership acquired a 33.75% interest (the "Anadarko-Operated Marcellus Interest") in each of the Larry's Creek, Seely and Warrensville gas gathering systems (the "Anadarko-Operated Marcellus Interest systems"), which are operated by Anadarko and serve production from the Marcellus shale in North-central Pennsylvania, from a third party. During the third quarter of 2013, the Partnership recorded a $1.1 million decrease in the assets acquired

and liabilities assumed in the acquisition, representing the final purchase price allocation.

(5) The Partnership acquired a 25% interest in the Mont Belvieu JV, an entity formed to design, construct, and own two fractionation trains located in Mont Belvieu, Texas, from a third party. The interest acquired is accounted for under the equity method of accounting.

(6) The Partnership acquired Overland Trail Transmission, LLC (“OTTCO”), a Delaware limited liability company, from a third party. OTTCO owns and operates an intrastate pipeline that connects the Partnership’s Red Desert and Granger complexes in southwestern Wyoming.

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

(8) The Partnership acquired Nuevo Midstream, LLC (“Nuevo”) from a third party. Following the acquisition, the Partnership changed the name of Nuevo to Delaware Basin Midstream, LLC (“DBM”). The assets acquired include cryogenic processing plants, a gas gathering system, and related facilities and equipment, which serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico. These assets are referred to collectively as the “DBM complex.” See Note 4 for a discussion of the Class C units.

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2. ACQUISITIONS (CONTINUED)

DBM acquisition. The DBM acquisition has been accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in the DBM acquisition were recorded in the consolidated balance sheet at their estimated fair values as of the acquisition date. Results of operations attributable to the DBM acquisition were included in the Partnership's consolidated statement of income beginning on the acquisition date in the fourth quarter of 2014.
The following is the preliminary allocation of the purchase price to the assets acquired and liabilities assumed in the DBM acquisition as of the acquisition date, pending the acquired entity's final financial statements:

thousands	
Current assets	$46,358
Property, plant and equipment	440,971
Goodwill	279,051
Other intangible assets	835,566
Accounts payables	(13,064)
Accrued liabilities	(24,824)
Deferred income taxes	(1,450)
Asset retirement obligations and other	(8,649)
Total purchase price	$1,553,959

The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the DBM acquisition using inputs that are not observable in the market and thus represent Level 3 inputs. The fair values of the processing plants, gathering system, and related facilities and equipment are based on market and cost approaches. The fair value of the intangible assets was determined using an income approach. Deferred taxes represent the tax effects of differences in the tax basis and acquisition-date fair value of the assets acquired and liabilities assumed.
The following table presents pro forma condensed financial information of the Partnership as if the DBM acquisition had occurred on January 1, 2013:

	Year Ended December 31,	
thousands except per-unit amounts	2014	2013
Revenues	$1,397,030	$1,107,030
Net income	332,420	239,382
Net income attributable to Western Gas Partners, LP	318,395	228,566
Net income per common unit – basic and diluted	1.34	1.12

The pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the DBM acquisition been completed at the assumed date, nor is it necessarily indicative of future operating results of the combined entity. The Partnership's pro forma information in the table above includes $12.5 million of revenues and $10.4 million of operating expenses, excluding depreciation, amortization and impairments, attributable to the DBM complex that are included in the Partnership's consolidated statement of income for the year ended December 31, 2014. The pro forma adjustments reflect pre-acquisition results of the DBM acquisition including (a) revenues and expenses; (b) depreciation and amortization based on the purchase price allocated to property, plant and equipment and estimated useful lives; (c) amortization of intangible assets (customer contracts assumed in the acquisition); and (d) interest on borrowings under the Partnership's senior unsecured revolving credit facility ("RCF") to finance the DBM acquisition. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the transaction are properly reflected. The pro forma information does not reflect any cost savings or other synergies anticipated as a result of the DBM acquisition, nor any future acquisition related expenses.

3. PARTNERSHIP DISTRIBUTIONS

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

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2012			
March 31	$0.460	$46,053	May 2012
June 30	0.480	52,425	August 2012
September 30	0.500	56,346	November 2012
December 31	0.520	65,657	February 2013
2013			
March 31	$0.540	$70,143	May 2013
June 30	0.560	79,315	August 2013
September 30	0.580	83,986	November 2013
December 31	0.600	92,609	February 2014
2014			
March 31	$0.625	$98,749	May 2014
June 30	0.650	105,655	August 2014
September 30	0.675	111,608	November 2014
December 31 (1)	0.700	126,044	February 2015

(1) On January 22, 2015, the Board of Directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders of $0.700 per unit, or $126.0 million in aggregate, including incentive distributions, but excluding distributions on Class C units (see Class C unit distributions below). The cash distribution was paid on February 12, 2015, to unitholders of record at the close of business on February 2, 2015.

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

3. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

Class C unit distributions. The Class C units receive quarterly distributions at a rate equivalent to the Partnership's common units. The distributions are paid in the form of additional Class C units ("PIK C units") until the end of 2017 (unless earlier converted, see Note 4), and the Class C units are disregarded with respect to distributions of the Partnership's available cash until they are converted to common units. The number of additional PIK C units to be issued in connection with a distribution payable on the Class C units is determined by dividing the corresponding distribution attributable to the Class C units by the volume-weighted-average price of the Partnership's common units for the ten days immediately preceding the payment date for the common unit distribution, less a 6% discount. The Partnership records the PIK C distributions at fair value at the time of issuance. This fair value measurement uses the Partnership's unit price as a significant input in the determination of the fair value and thus represents a Level 2 measurement. On February 12, 2015, the Partnership's general partner distributed 45,711 PIK C units to the Class C unitholder, based on the $0.700 common unit distribution referenced above, with an implied fair value of $3.1 million. The Class C unit distribution was prorated for the 37-day period the Class C units were outstanding during the fourth quarter of 2014.

General partner interest and incentive distribution rights. As of December 31, 2014, the general partner was entitled to 1.9% of all quarterly distributions that the Partnership makes prior to its liquidation (see Note 4). The Partnership's general partner, as the holder of the IDRs, was entitled to incentive distributions at the maximum distribution sharing percentage of 48.0% for all periods presented.

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.300	98.1%	1.9%
First target distribution	up to $0.345	98.1%	1.9%
Second target distribution	above $0.345 up to $0.375	85.1%	14.9%
Third target distribution	above $0.375 up to $0.450	75.1%	24.9%
Thereafter	above $0.450	50.1%	49.9%

The maximum distribution sharing percentage of 49.9% includes distributions paid to the general partner on its 1.9% general partner interest and the 48.0% IDR maximum distribution sharing percentage, and does not include any distributions that the general partner may receive on common units that it may acquire.

4. EQUITY AND PARTNERS' CAPITAL

Equity offerings. The Partnership completed the following public offerings of its common units during 2014, 2013 and 2012:

thousands except unit and per-unit amounts	Common Units Issued	GP Units Issued [1]	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
June 2012 equity offering	5,000,000	102,041	$43.88	$7,468	$216,409
May 2013 equity offering [2]	7,015,000	143,163	61.18	13,203	424,733
December 2013 equity offering [3]	4,800,000	97,959	61.51	9,447	291,827
Continuous Offering Program - 2013 [4]	685,735	13,996	60.84	965	41,603
Continuous Offering Program - 2014 [5]	1,133,384	23,132	73.48	1,738	83,245
November 2014 equity offering [6]	8,620,153	153,061	70.85	18,583	602,999

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

(2) Includes the issuance of 915,000 common units pursuant to the full exercise of the underwriters' over-allotment option.

(3) Includes the issuance of 300,000 common units on January 3, 2014, pursuant to the partial exercise of the underwriters' over-allotment option. Net proceeds from this partial exercise (including the general partner's proportionate capital contribution) were $18.1 million.

(4) Represents common and general partner units issued during the year ended December 31, 2013, pursuant to the Partnership's registration statement filed with the U.S. Securities and Exchange Commission ("SEC") in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the "Continuous Offering Program"). Gross proceeds generated (including the general partner's proportionate capital contributions) during the year ended December 31, 2013, were $42.6 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during 2013.

(5) Represents common and general partner units issued during the year ended December 31, 2014, under the Continuous Offering Program. Gross proceeds generated (including the general partner's proportionate capital contributions) during the year ended December 31, 2014, were $85.0 million. The price per unit in the table above represents an average price for all issuances under the Continuous Offering Program during the year ended December 31, 2014. As of December 31, 2014, the Partnership had used all the capacity to issue common units under this registration statement.

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

Common and general partner units. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."

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

4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

The Class C units were issued at a discount to the then-current market price of the common units into which they are convertible. This discount, totaling $34.8 million, represents a beneficial conversion feature and is reflected as an increase in common unitholders' capital and a decrease in Class C unitholder capital to reflect the fair value of the Class C units at issuance. The beneficial conversion feature is considered a non-cash distribution that will be recognized from the date of issuance through the date of conversion, resulting in an increase in Class C unitholder capital and a decrease in common unitholders' capital. The Partnership will amortize the beneficial conversion feature assuming a conversion date of December 31, 2017, using the effective yield method. The impact of the beneficial conversion feature will also be included in the calculation of earnings per unit.
The following table summarizes the common, Class C and general partner units issued during the years ended December 31, 2014 and 2013:

	Common Units	Class C Units	General Partner Units	Total
Balance at December 31, 2012	104,660,553	—	2,135,930	106,796,483
Non-Operated Marcellus Interest acquisition	449,129	—	9,166	458,295
Long-Term Incentive Plan awards	12,395	—	253	12,648
May 2013 equity offering	7,015,000	—	143,163	7,158,163
Continuous Offering Program	685,735	—	13,996	699,731
December 2013 equity offering	4,500,000	—	91,837	4,591,837
Balance at December 31, 2013	117,322,812	—	2,394,345	119,717,157
December 2013 equity offering	300,000	—	6,122	306,122
Long-Term Incentive Plan awards	10,291	—	112	10,403
TEFR Interests acquisition	308,490	—	6,296	314,786
Continuous Offering Program	1,133,384	—	23,132	1,156,516
November 2014 equity offering	8,620,153	—	153,061	8,773,214
Class C unit issuance	—	10,913,853	—	10,913,853
Balance at December 31, 2014	127,695,130	10,913,853	2,583,068	141,192,051

Holdings of Partnership equity. As of December 31, 2014, WGP held 49,296,205 common units, representing a 34.9% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,583,068 general partner units, representing a 1.8% general partner interest in the Partnership, and 100% of the Partnership's IDRs. As of December 31, 2014, other subsidiaries of Anadarko held 757,619 common units and 10,913,853 Class C units, representing an aggregate 8.3% limited partner interest in the Partnership. As of December 31, 2014, the public held 77,641,306 common units, representing a 55.0% limited partner interest in the Partnership.
The Partnership's net income earned on and subsequent to the date of the acquisition of the Partnership assets (as defined in Note 1) is allocated to the general partner and the limited partners consistent with actual cash distributions, including incentive distributions allocable to the general partner. Undistributed earnings (net income in excess of distributions) or undistributed losses (available cash in excess of net income) are then allocated to the general partner and the limited partners in accordance with their respective ownership percentages.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

Net income per unit for common units. Basic net income per common unit is calculated by dividing the limited partners' interest in net income attributable to common unitholders by the weighted-average number of common units outstanding during the period. The common units issued in connection with acquisitions and equity offerings are included on a weighted-average basis for periods they were outstanding. Because the Class C units participate in distributions with common units according to a predetermined formula (see Note 3), they are considered a participating security and are included in the computation of earnings per unit pursuant to the two-class method. The Class C unit participation right results in a non-contingent transfer of value each time the Partnership declares a distribution. Diluted net income per common unit is calculated by dividing the sum of (i) the limited partners' interest in net income attributable to common units, and (ii) the limited partners' interest in net income allocable to the Class C units as a participating security, by the sum of the weighted-average number of common units outstanding plus the dilutive effect of outstanding Class C units.
The following table illustrates the Partnership's calculation of net income per unit for common units:

	Year Ended December 31,		
thousands except per-unit amounts	2014	2013	2012
Net income attributable to Western Gas Partners, LP	$376,533	$274,627	$134,377
Pre-acquisition net (income) loss allocated to Anadarko	956	(4,128)	(27,391)
General partner interest in net (income) loss	(120,980)	(69,633)	(28,089)
Limited partners' interest in net income	256,509	200,866	78,897
Net income allocable to common units	254,737	200,866	78,897
Net income allocable to Class C units	1,772	—	—
Limited partners' interest in net income	$256,509	$200,866	$78,897
Net income per unit			
Common units - basic	$2.13	$1.83	$0.84
Common units – diluted	2.12	1.83	0.84
Weighted-average units outstanding			
Common units – basic	119,822	109,872	93,936
Class C units	1,106	—	—
Common units – diluted	120,928	109,872	93,936

5. TRANSACTIONS WITH AFFILIATES

Affiliate transactions. Revenues from affiliates include amounts earned by the Partnership from services provided to Anadarko as well as from the sale of residue, condensate and NGLs to Anadarko. In addition, the Partnership purchases natural gas from an affiliate of Anadarko pursuant to gas purchase agreements. Operation and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership's general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership's omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 1 for further information related to contributions of assets to the Partnership by Anadarko.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition of the Partnership assets, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. Anadarko charged or credited the Partnership interest at a variable rate on outstanding affiliate balances for the periods these balances remained outstanding. The outstanding affiliate balances were entirely settled through an adjustment to net investment by Anadarko in connection with the acquisition of the Partnership assets. Subsequent to the acquisition of Partnership assets from Anadarko, transactions related to such assets are cash-settled directly with third parties and with Anadarko affiliates, and affiliate-based interest expense on current intercompany balances is not charged. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.

Note receivable from and amount payable to Anadarko. Concurrently with the closing of the Partnership's May 2008 IPO, the Partnership loaned $260.0 million to Anadarko in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The fair value of the note receivable from Anadarko was $317.8 million and $296.7 million at December 31, 2014 and 2013, respectively. The fair value of the note reflects consideration of credit risk and any premium or discount for the differential between the stated interest rate and quarter-end market interest rate, based on quoted market prices of similar debt instruments. Accordingly, the fair value of the note receivable from Anadarko is measured using Level 2 inputs.
In 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko, which was repaid in full in June 2012 using the proceeds from the issuance of 4.000% Senior Notes due 2022. See Note 12.

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

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

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

The following table summarizes realized gains and losses on commodity price swap agreements:

	Year Ended December 31,		
thousands	2014	2013	2012
Gains (losses) on commodity price swap agreements related to sales: (1)			
Natural gas sales	$9,494	$21,382	$37,665
Natural gas liquids sales	113,866	102,076	66,260
Total	123,360	123,458	103,925
Losses on commodity price swap agreements related to purchases (2)	(68,492)	(85,294)	(89,710)
Net gains (losses) on commodity price swap agreements	$54,868	$38,164	$14,215

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

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

Gas gathering and processing agreements. The Partnership has significant gas gathering and processing arrangements with affiliates of Anadarko on a majority of its systems. The Partnership’s gathering, transportation and treating throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 48%, 54% and 62% for the years ended December 31, 2014, 2013 and 2012, respectively. The Partnership’s processing throughput (excluding equity investment throughput and throughput measured in barrels) attributable to natural gas production owned or controlled by Anadarko was 57%, 59% and 61% for the years ended December 31, 2014, 2013 and 2012, respectively. Throughput percentages are not directly comparable because the formation of the DJ Basin complex resulted in the following: (i) the Wattenberg system volumes previously reported as “Gathering, treating and transportation” are now reported as “Processing” for all periods presented, and (ii) beginning in 2014, volumes both gathered and processed by the two systems are no longer separately reported.

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

Omnibus agreement. Pursuant to the omnibus agreement, Anadarko performs centralized corporate functions for the Partnership, such as legal; accounting; treasury; cash management; investor relations; insurance administration and claims processing; risk management; health, safety and environmental; information technology; human resources; credit; payroll; internal audit; tax; marketing; and midstream administration. Anadarko, in accordance with the partnership and omnibus agreements, determines, in its reasonable discretion, amounts to be reimbursed by the Partnership in exchange for services provided under the omnibus agreement. See Summary of affiliate transactions below.

The following table summarizes the amounts the Partnership reimbursed to Anadarko:

	Year Ended December 31,		
thousands	2014	2013	2012
General and administrative expenses	$20,249	$16,882	$14,904
Public company expenses	8,006	7,152	6,830

Total reimbursement	$28,255	$24,034	$21,734

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Services and secondment agreement. Pursuant to the services and secondment agreement, specified employees of Anadarko are seconded to the general partner to provide operating, routine maintenance and other services with respect to the assets owned and operated by the Partnership under the direction, supervision and control of the general partner. Pursuant to the services and secondment agreement, the Partnership reimburses Anadarko for services provided by the seconded employees. The initial term of the services and secondment agreement extends through May 2018 and the term will automatically extend for additional twelve-month periods unless either party provides 180 days written notice of termination before the applicable twelve-month period expires. The consolidated financial statements include costs allocated by Anadarko for expenses incurred under the services and secondment agreement for periods including and subsequent to the Partnership's acquisition of the Partnership assets.

Tax sharing agreement. Pursuant to a tax sharing agreement, the Partnership reimburses Anadarko for its estimated share of applicable state taxes. These taxes include income taxes attributable to the Partnership's income which are directly borne by Anadarko through its filing of a combined or consolidated tax return with respect to periods beginning on and subsequent to the acquisition of the Partnership assets from Anadarko. Anadarko may use its own tax attributes to reduce or eliminate the tax liability of its combined or consolidated group, which may include the Partnership as a member. However, under this circumstance, the Partnership nevertheless is required to reimburse Anadarko for its allocable share of taxes that would have been owed had tax attributes not been available to Anadarko.

Allocation of costs. For periods prior to the Partnership's acquisition of the Partnership assets, the consolidated financial statements 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. This management services fee was allocated to the Partnership based on its proportionate share of Anadarko's assets and revenues or other contractual arrangements. Management believes these allocation methodologies are reasonable.
The employees supporting the Partnership's operations are employees of Anadarko. Anadarko allocates costs to the Partnership for its share of personnel costs, including costs associated with equity-based compensation plans, non-contributory defined pension and postretirement plans, defined contribution savings plan pursuant to the omnibus agreement and services and secondment agreement. In general, the Partnership's reimbursement to Anadarko under the omnibus agreement or services and secondment agreements is either (i) on an actual basis for direct expenses Anadarko and the general partner incur on behalf of the Partnership, or (ii) based on an allocation of salaries and related employee benefits between the Partnership, the general partner and Anadarko based on estimates of time spent on each entity's business and affairs. Most general and administrative expenses charged to the Partnership by Anadarko are attributed to the Partnership on an actual basis, and do not include any mark-up or subsidy component. With respect to allocated costs, management believes the allocation method employed by Anadarko is reasonable. Although it is not practicable to determine what the amount of these direct and allocated costs would be if the Partnership were to directly obtain these services, management believes that aggregate costs charged to the Partnership by Anadarko are reasonable.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

WES LTIP. The general partner awards phantom units under the WES LTIP primarily to its independent directors and its Chief Executive Officer. The phantom units awarded to the independent directors vest one year from the grant date, while all other awards are subject to graded vesting over a three-year service period. Compensation expense is recognized over the vesting period and was $0.6 million for each of the years ended December 31, 2014 and 2013, and $0.4 million for the year ended December 31, 2012. As of December 31, 2014, there was $0.3 million of unrecognized compensation expense attributable to the outstanding awards under the WES LTIP, of which $0.2 million will be realized by the Partnership, and which is expected to be recognized over a weighted-average period of 0.7 years.
The following table summarizes WES LTIP award activity for the years ended December 31, 2014, 2013 and 2012:

	2014		2013		2012	
	Weighted-Average Grant-Date Fair Value	Units	Weighted-Average Grant-Date Fair Value	Units	Weighted-Average Grant-Date Fair Value	Units
Phantom units outstanding at beginning of year	$49.47	16,844	$41.77	25,619	$33.92	23,978
Vested	49.55	(13,122)	41.28	(14,695)	33.20	(14,260)
Granted	68.14	5,800	62.49	5,920	45.91	15,901
Phantom units outstanding at end of year	60.74	9,522	49.47	16,844	41.77	25,619

WGP LTIP and Anadarko Incentive Plans. For the years ended December 31, 2014, 2013 and 2012, general and administrative expenses included $3.5 million, $3.0 million and $3.3 million, respectively, of equity-based compensation expense, allocated to the Partnership by Anadarko, for awards granted to the executive officers of the general partner and other employees under the WGP LTIP and Anadarko Incentive Plans. Of these amounts, $3.2 million, $2.9 million and $3.2 million for the years ended December 31, 2014, 2013 and 2012, respectively, of allocated equity-based compensation expense is reflected as a contribution to partners' capital in the Partnership's consolidated statements of equity and partners' capital. As of December 31, 2014, the Partnership estimated that $7.2 million of unrecognized compensation expense attributable to the WGP LTIP and the Anadarko Incentive Plans will be allocated to the Partnership over a weighted-average period of 2.1 years.

The Incentive Plan. For the year ended December 31, 2012, the Partnership's general and administrative expenses included $68.8 million of compensation expense for grants of Unit Value Rights ("UVRs"), Unit Appreciation Rights ("UARs") and Distribution Equivalent Rights ("DERs") under the Incentive Plan to certain executive officers of the general partner as a component of their compensation, which was allocated to the Partnership by Anadarko.
Under the terms of the Incentive Plan, the value of a UAR was equal to an amount calculated by dividing the "determined value" (defined below) by 1,000,000, less the applicable UAR exercise price. Prior to WGP's IPO in December 2012, the value of awards issued under the Incentive Plan were revised periodically based on the estimated fair value of the Partnership's general partner using a discounted cash flow estimate and multiples-valuation terminal value.

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Anadarko and the Incentive Plan participants entered into a Memorandum of Understanding (the "MOU") that, among other things, confirmed the intent and the understanding that the WGP IPO resulted in the vesting of all unvested Incentive Plan awards and that the value of the Partnership's common units held by WGP prior to its IPO would not be considered in the valuation of the Incentive Plan awards.
The WGP IPO and concurrent execution of the MOU triggered the exercise of all outstanding UARs and lump-sum cash payments (less any applicable withholding taxes) to plan participants equal to the value of each award, less its exercise price, if applicable. Pursuant to the MOU, the "determined value" was defined as equal to the aggregate WGP equity value, as determined using the market price of WGP based on the IPO price of WGP's common units, reduced by the market value of the Partnership's common units owned by WGP prior to its IPO (based on the closing price of the Partnership's common units on the day of the pricing of the IPO). Awards outstanding under the Incentive Plan at the time of the WGP IPO (and the effective termination of the Incentive Plan) were valued at $2,745.00 per UAR and $12.00 per DER. Outstanding UVRs that vested concurrent with the WGP IPO were cash-settled at their grant-date fair value.
In addition to the execution of the MOU, WGP, the Partnership's general partner and Anadarko entered into a contribution agreement whereby cash, in an amount equal to the aggregate cash payment required to settle all outstanding awards, was contributed to the Partnership's general partner by Anadarko. The cash payments made in connection with WGP's IPO and the vesting, exercise and settlement of all outstanding awards under the Incentive Plan as described above, impacted the Partnership's cash flows to the extent compensation expense was allocated to the Partnership since the inception of the Incentive Plan. The compensation expense allocated to the Partnership since the inception of the Incentive Plan, and subsequently contributed by Anadarko during the fourth quarter of 2012, was recorded to partners' capital in the consolidated financial statements.

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

	Year Ended December 31,					
	2014	2013	2012	2014	2013	2012
thousands	Purchases			Sales		
Cash consideration	$22,943	$11,211	$24,705	$—	$85	$760
Net carrying value	12,210	5,309	8,009	—	38	393
Partners' capital adjustment	$10,733	$5,902	$16,696	$—	$47	$367

Contributions in aid of construction costs from affiliates. In 2013, a subsidiary of Anadarko entered into an aid in construction agreement with the Partnership, whereby the Partnership constructed five receipt-point facilities at the Brasada complex that serve the Anadarko subsidiary. Such subsidiary reimbursed the Partnership for costs associated with construction of the receipt points. These reimbursements are presented within the investing section of the Partnership's consolidated statements of cash flows as "Contributions in aid of construction costs from affiliates."

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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

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

	Year ended December 31,		
thousands	2014	2013	2012
Revenues (1)	$969,995	$805,526	$688,026
Equity income, net (1)	57,836	22,948	16,042
Cost of product (1)	114,000	129,045	145,250
Operation and maintenance (2)	58,884	56,435	51,237
General and administrative (3)	26,989	23,354	92,847
Operating expenses	199,873	208,834	289,334
Interest income (4)	16,900	16,900	16,900
Interest expense (5)	—	—	2,766
Distributions to unitholders (6)	234,024	169,150	98,280
Contributions from noncontrolling interest owners (7)	—	—	12,588
Distributions to noncontrolling interest owners (7)	—	—	6,528

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

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

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

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

(5) For the year ended December 31, 2012, includes interest expense recognized on the note payable to Anadarko (see Note 12) and interest imputed on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada complex and Lancaster plant. The Partnership repaid the note payable to Anadarko in June 2012, and repaid the reimbursement payable to Anadarko associated with the construction of the Brasada complex and Lancaster plant in the fourth quarter of 2012.

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

(7) As described in Note 2, the Partnership acquired the additional Chipeta interest on August 1, 2012, and accounted for the acquisition on a prospective basis. As such, contributions from noncontrolling interest owners and distributions to noncontrolling interest owners subsequent to the acquisition date no longer reflect contributions from or distributions to Anadarko.

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

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6. INCOME TAXES

The components of the Partnership's income tax expense (benefit) are as follows:

	Year Ended December 31,		
thousands	2014	2013	2012
Current income tax expense (benefit)			
Federal income tax expense (benefit)	$(625)	$(30,176)	$(7,576)
State income tax expense (benefit)	69	640	(1,843)
Total current income tax expense (benefit)	(556)	(29,536)	(9,419)
Deferred income tax expense (benefit)			
Federal income tax expense (benefit)	171	32,930	22,324
State income tax expense (benefit)	2,412	(1,039)	7,785
Total deferred income tax expense (benefit)	2,583	31,891	30,109
Total income tax expense	$2,027	$2,355	$20,690

Total income taxes differed from the amounts computed by applying the statutory income tax rate to income before income taxes. The sources of these differences are as follows:

	Year Ended December 31,		
thousands except percentages	2014	2013	2012
Income before income taxes	$392,585	$287,798	$169,957
Statutory tax rate	— %	— %	— %
Tax computed at statutory rate	$—	$—	$—
Adjustments resulting from:			
Federal taxes on income attributable to Partnership assets pre-acquisition	(454)	3,090	17,226
State taxes on income attributable to Partnership assets pre-acquisition (net of federal benefit)	—	624	2,206
Texas margin tax expense (benefit)	2,481	(1,359)	1,258
Income tax expense	$2,027	$2,355	$20,690
Effective tax rate	1 %	1 %	12 %

The tax effects of temporary differences that give rise to significant portions of deferred tax assets (liabilities) are as follows:

	December 31,	
thousands	2014	2013
Credit carryforwards	$14	$14
Net current deferred income tax assets	14	14
Depreciable property	(3,240)	(38,528)
Credit carryforwards	512	527
Other intangible assets	(1,450)	—
Other	7	3
Net long-term deferred income tax liabilities	(4,171)	(37,998)
Total net deferred income tax liabilities	$(4,157)	$(37,984)

Credit carryforwards, which are available for use on future income tax returns, consist of $0.5 million of state income tax credits that expire in 2026.

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7. PROPERTY, PLANT AND EQUIPMENT

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

		December 31,	
thousands	Estimated Useful Life	2014	2013
Land	n/a	$2,839	$2,584
Gathering systems	3 to 47 years	4,790,974	3,673,008
Pipelines and equipment	15 to 45 years	151,107	146,008
Assets under construction	n/a	464,507	405,633
Other	3 to 40 years	15,272	11,867
Total property, plant and equipment		5,424,699	4,239,100
Accumulated depreciation		1,040,328	855,845
Net property, plant and equipment		$4,384,371	$3,383,255

The cost of property classified as “Assets under construction” is excluded from capitalized costs being depreciated. These amounts represent property that is not yet suitable to be placed into productive service as of the respective balance sheet date.

At December 31, 2013, other long-term assets includes $4.6 million of unguaranteed residual value related to the capital lease component of a processing agreement assumed in connection with the acquisition of the Granger straddle plant as a part of the MGR acquisition in January 2012. This agreement, in which the Partnership was the lessor, was replaced effective April 1, 2014, with a gas conditioning agreement that does not satisfy criteria required for lease classification. As such, during the second quarter of 2014, the Partnership reclassified the $4.6 million capital lease asset from other long-term assets to property, plant and equipment and commenced depreciation.

During 2014, the Partnership recognized impairments of $3.1 million, primarily related to a non-operational plant in the Powder River Basin that was impaired to its estimated fair value of $2.4 million, using Level 3 fair-value inputs, the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems and a compressor no longer in service at the Hilight system.

During 2013, the Partnership recognized a $1.2 million impairment primarily related to the cancellation of various capital projects by the third-party operator of the Non-Operated Marcellus Interest systems.

During 2012, the Partnership recognized a $6.0 million impairment related to a gathering system in central Wyoming that was impaired to its estimated fair value using Level 3 fair-value inputs and an impairment of $0.6 million for the original installation costs on a compressor relocated within the Partnership’s operating assets.

8. GOODWILL AND INTANGIBLES

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, 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, the Partnership's allocated goodwill balance does not represent, and in some cases is significantly different from, the difference between the consideration the Partnership paid for its acquisitions from Anadarko and the fair value of such net assets on their respective acquisition dates.

The consolidated balance sheets as of December 31, 2014 and 2013, include goodwill of $384.4 million and $105.3 million, respectively, the impairment of which (if applicable) is not deductible for tax purposes. The Partnership recorded $279.1 million of goodwill in connection with the acquisition of DBM (see Note 2).

The Partnership evaluates goodwill for impairment annually (see Note 1). Estimating the fair value of the Partnership's reporting units was not necessary based on the qualitative evaluation as of October 1, 2014, and no goodwill impairment has been recognized in these consolidated financial statements. Procedures were also performed in the fourth quarter of 2014 to review any changes in circumstances subsequent to the annual test, including changes in commodity prices. These procedures also indicated no impairment.

Other intangible assets. The intangible asset balance in the consolidated balance sheets includes the fair value, net of amortization, of (i) contracts assumed by the Partnership 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 assumed by the Partnership in connection with the DBM acquisition in November 2014, which are being amortized on a straight-line basis over 30 years.

The Partnership assesses intangible assets for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See Property, plant and equipment in Note 1 for further discussion of management's process to evaluate potential impairment of long-lived assets. No intangible asset impairment has been recognized in these consolidated financial statements.

The following table presents the gross carrying amount and accumulated amortization of other intangible assets:

	December 31,	
thousands	2014	2013
Gross carrying amount	$892,555	$56,988
Accumulated amortization	(7,698)	(3,382)
Other intangible assets	$884,857	$53,606

Amortization expense for intangible assets was $4.3 million, $1.4 million and $1.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The Partnership estimates that it will record $29.1 million of intangible asset amortization during 2015 and $29.2 million for each of the following four years.

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9. EQUITY INVESTMENTS

The following table presents the activity in the Partnership's equity investments for the years ended December 31, 2014 and 2013:

	Equity Investments							
thousands	Fort Union [1]	White Cliffs [2]	Rendezvous [3]	Mont Belvieu JV [4]	TEG [5]	TEP [6]	FRP [7]	Total
Balance at December 31, 2012	$23,453	$17,567	$65,110	$—	$9,033	$80,737	$23,866	$219,766
Initial investment	—	—	—	78,129	—	—	—	78,129
Investment earnings (loss), net of amortization	6,273	9,681	2,088	5,690	93	(776)	(101)	22,948
Contributions	16	19,087	—	37,309	6,732	108,969	105,547	277,660
Capitalized interest	—	—	—	1,352	791	8,801	6,089	17,033
Distributions	(4,570)	(9,099)	(4,029)	—	—	—	—	(17,698)
Distributions in excess of cumulative earnings [8]	—	(2,197)	(2,241)	—	—	—	—	(4,438)
Balance at December 31, 2013	$25,172	$35,039	$60,928	$122,480	$16,649	$197,731	$135,401	$593,400
Investment earnings (loss), net of amortization	6,344	11,912	1,729	29,029	650	6,108	2,064	57,836
Contributions	—	10,456	—	3,957	352	6,623	42,033	63,421
Capitalized interest	—	—	—	—	—	—	857	857
Distributions	(5,583)	(11,330)	(3,669)	(34,129)	(523)	(5,622)	(2,111)	(62,967)
Distributions in excess of cumulative earnings [8]	—	(1,762)	(2,652)	—	(338)	(6,047)	(7,256)	(18,055)
Balance at December 31, 2014	$25,933	$44,315	$56,336	$121,337	$16,790	$198,793	$170,988	$634,492

(1) The Partnership has a 14.81% interest in Fort Union, a joint venture that owns a gathering pipeline and treating facilities in the Powder River Basin. Anadarko is the construction manager and physical operator of the Fort Union facilities. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the owners' firm gathering agreements, require 65% or unanimous approval of the owners.

(2) The Partnership has a 10% interest in White Cliffs, a limited liability company that owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. The third-party majority owner is the manager of the White Cliffs operations. Certain business decisions, including, but not limited to, approval of annual budgets and decisions with respect to significant expenditures, contractual commitments, acquisitions, material financings, dispositions of assets or admitting new members, require more than 75% approval of the members.

(3)

The Partnership has a 22% interest in Rendezvous, a limited liability company that operates gas gathering facilities in Southwestern Wyoming. Certain business decisions, including, but not limited to, decisions with respect to significant expenditures or contractual commitments, annual budgets, material financings, dispositions of assets or amending the members' gas servicing agreements, require unanimous approval of the members.

(4) The Partnership has a 25% interest in the Mont Belvieu JV, an entity formed to design, construct, and own two fractionation trains located in Mont Belvieu, Texas. A third party is the operator of the Mont Belvieu JV fractionation trains. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer positions require 50% or unanimous approval of the owners.

(5) The Partnership has a 20% interest in TEG, an entity that consists of two NGL gathering systems that link natural gas processing plants to TEP. Enbridge Midcoast Energy, LP ("Enbridge") is the operator of the two gathering systems. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the delegation, creation, appointment, or removal of officer positions require more than 50% approval of the members.

(6) The Partnership has a 20% interest in TEP, which consists of an NGL pipeline that originates in Skellytown, Texas and extends to Mont Belvieu, Texas. Enterprise Products Operating LLC ("Enterprise") is the operator of TEP. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer positions require more than 50% approval of the members.

(7) The Partnership has a 33.33% interest in the FRP, an NGL pipeline that extends from Weld County, Colorado to Skellytown, Texas. Enterprise is the operator of FRP. Certain business decisions, including, but not limited to, decisions with respect to the execution of contracts, settlements, disposition of assets, or the creation, appointment, or removal of officer positions require more than 50% approval of the members.

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

9. EQUITY INVESTMENTS (CONTINUED)

The investment balance at December 31, 2014, includes $2.3 million and $42.1 million for the purchase price allocated to the investment in Fort Union and Rendezvous, respectively, in excess of the historic cost basis of Western Gas Resources, Inc. (“WGRI”), the entity that previously owned the interests in Fort Union and Rendezvous, which Anadarko acquired in August 2006. This excess balance is attributable to the difference between the fair value and book value of such gathering and treating facilities (at the time WGRI was acquired by Anadarko) and is being amortized over the remaining estimated useful life of those facilities.

The investment balance in White Cliffs at December 31, 2014, is $9.0 million less than the Partnership’s underlying equity in White Cliffs’ net assets, primarily due to the Partnership recording the acquisition of its initial 0.4% interest in White Cliffs at Anadarko’s historic carrying value. This difference is being amortized to equity income, net over the remaining estimated useful life of the White Cliffs pipeline.

Management evaluates its equity investments for impairment whenever events or changes in circumstances indicate that the carrying value of such investments may have experienced a decline in value that is other than temporary. When evidence of loss in value has occurred, management compares the estimated fair value of the investment to the carrying value of the investment to determine whether the investment has been impaired. Management assesses the fair value of equity investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third-party comparable sales and discounted cash flow models. If the estimated fair value is less than the carrying value, the excess of the carrying value over the estimated fair value is recognized as an impairment loss.

The following tables present the summarized combined financial information for the Partnership’s equity investments (amounts represent 100% of investee financial information):

	Year Ended December 31,		
thousands	2014	2013	2012
Consolidated Statements of Income			
Revenues	$548,629	$261,705	$199,764
Operating income	336,188	171,496	135,498
Net income	333,705	170,175	133,987

	December 31,	
thousands	2014	2013
Consolidated Balance Sheets		
Current assets	$141,781	$186,690
Property, plant and equipment, net	2,814,336	2,676,531
Other assets	48,799	38,258
Total assets	$3,004,916	$2,901,479
Current liabilities	95,102	206,602
Non-current liabilities	22,615	34,012
Equity	2,887,199	2,660,865
Total liabilities and equity	$3,004,916	$2,901,479

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10. COMPONENTS OF WORKING CAPITAL

A summary of other current assets is as follows:

	December 31,	
thousands	2014	2013
Natural gas liquids inventory	$5,316	$2,584
Natural gas imbalance receivables	415	3,605
Prepaid insurance	2,443	2,123
Other	1,893	1,710
Total other current assets	$10,067	$10,022

A summary of accrued liabilities is as follows:

	December 31,	
thousands	2014	2013
Accrued capital expenditures	$116,891	$94,750
Accrued plant purchases	14,023	21,396
Accrued interest expense	24,741	18,119
Short-term asset retirement obligations	1,212	1,966
Short-term remediation and reclamation obligations	475	562
Income taxes payable	207	—
Other	1,106	218
Total accrued liabilities	$158,655	$137,011

11. ASSET RETIREMENT OBLIGATIONS

The following table provides a summary of changes in asset retirement obligations:

	Year Ended December 31,	
thousands	2014	2013
Carrying amount of asset retirement obligations at beginning of year	$78,035	$66,723
Liabilities incurred	13,769	14,143
Liabilities settled	(4,181)	(1,943)
Accretion expense	4,846	4,326
Revisions in estimated liabilities	16,623	(5,214)
Carrying amount of asset retirement obligations at end of year	$109,092	$78,035

Revisions in estimated liabilities for the year ended December 31, 2014, are related to changes in estimated inflation rates, changes in property lives and changes in the expected timing of settlement primarily at the DJ Basin complex, Granger complex, Hugoton and Hilight systems, MIGC, OTTCO, Brasada complex and Non-Operated Marcellus Interest systems. The liabilities incurred for the year ended December 31, 2014, increased primarily due to the acquisition of DBM in the fourth quarter of 2014 and continued capital expansion at the DJ Basin complex. Revisions in estimated liabilities for the year ended December 31, 2013, related primarily to the change in the estimated timing of settling the Partnership’s asset retirement obligations at the DJ Basin complex. The liabilities incurred for the year ended December 31, 2013, represented the increase in capital expansion at the DJ Basin complex, the Hilight system and the June 2013 completion of the Brasada complex.

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12. DEBT AND INTEREST EXPENSE

At December 31, 2014, the Partnership's debt consisted of 5.375% Senior Notes due 2021 (the "2021 Notes"), 4.000% Senior Notes due 2022 (the "2022 Notes"), 2.600% Senior Notes due 2018 (the "2018 Notes"), 5.450% Senior Notes due 2044 (the "2044 Notes"), and borrowings on the RCF. The two tranches of the 2022 Notes, issued in June and October 2012, were issued under the same indenture and are considered a single class of securities. The two tranches of the 2018 Notes, issued in August 2013 and March 2014, were issued under the same indenture and are considered a single class of securities.

The following table presents the Partnership's outstanding debt as of December 31, 2014 and 2013:

	December 31, 2014			December 31, 2013		
thousands	Principal	Carrying Value	Fair Value [1]	Principal	Carrying Value	Fair Value [1]
5.375% Senior Notes due 2021	$500,000	$495,714	$549,530	$500,000	$495,173	$533,615
4.000% Senior Notes due 2022	670,000	672,930	681,942	670,000	673,278	641,237
Revolving credit facility	510,000	510,000	510,000	—	—	—
2.600% Senior Notes due 2018	350,000	350,474	352,162	250,000	249,718	247,988
5.450% Senior Notes due 2044	400,000	393,836	417,619	—	—	—
Total long-term debt	$2,430,000	$2,422,954	$2,511,253	$1,420,000	$1,418,169	$1,422,840

[1] Fair value is measured using Level 2 inputs.

Debt activity. The following table presents the debt activity of the Partnership for the years ended December 31, 2014 and 2013:

thousands	Carrying Value
Balance at December 31, 2012	$1,168,278
Revolving credit facility borrowings	710,000
Repayments of revolving credit facility	(710,000)
Issuance of 2.600% Senior Notes due 2018	250,000
Other	(109)
Balance at December 31, 2013	$1,418,169
Revolving credit facility borrowings	1,160,000
Issuance of 5.450% Senior Notes due 2044	400,000
Issuance of 2.600% Senior Notes due 2018	100,000
Repayments of revolving credit facility	(650,000)
Other	(5,215)
Balance at December 31, 2014	$2,422,954

Senior Notes. The 2044 Notes issued in March 2014 were offered at a price to the public of 98.443% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2044 Notes is 5.633%. Interest is paid semi-annually on April 1 and October 1 of each year. Proceeds (net of underwriting discount of $3.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under the Partnership's RCF and for general partnership purposes.

The 2018 Notes issued in March 2014 were offered at a price to the public of 100.857% of the face amount. Including the effects of the issuance premium for the March 2014 offering, the issuance discount for the August 2013 offering of 2018 Notes and underwriting discounts, the effective interest rate of the 2018 Notes is 2.743%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $0.6 million, original issue premium and debt issuance costs) were used to repay amounts then outstanding under the Partnership's RCF and for general partnership purposes.

12. DEBT AND INTEREST EXPENSE (CONTINUED)

At December 31, 2014, the Partnership was in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, 2018 Notes and 2044 Notes.

Interest rate agreements. In May 2012, the Partnership entered into U.S. Treasury Rate lock agreements to mitigate the risk of rising interest rates prior to the issuance of the 2022 Notes. The Partnership settled the rate lock agreements simultaneously with the June 2012 offering of the 2022 Notes, realizing a loss of $1.7 million, which is included in other income (expense), net in the consolidated statements of income.

Note payable to Anadarko. In 2008, the Partnership entered into a five-year $175.0 million term loan agreement with Anadarko. The interest rate was fixed at 2.82% prior to June 2012 when the note payable to Anadarko was repaid in full with proceeds from the June 2012 offering of the 2022 Notes.

Revolving credit facility. In February 2014, the Partnership entered into its amended and restated $1.2 billion senior unsecured RCF, which is expandable to a maximum of $1.5 billion, replacing an $800.0 million credit facility, which was originally entered into in March 2011. Subsequent to February 2014, the Partnership borrowed $350.0 million under the RCF to fund the acquisition of the TEFR Interests (see Note 2). The RCF matures in February 2019 and bears interest at London Interbank Offered Rate (“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 the Partnership’s senior unsecured debt rating. The interest rate on the RCF was 1.47% at December 31, 2014. At December 31, 2013, the interest rate on the previous credit facility was 1.67%. The Partnership is 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 the Partnership’s senior unsecured debt rating. The facility fee rate was 0.20% and 0.25% at December 31, 2014 and 2013, respectively.

As of December 31, 2014, the Partnership had $510.0 million of outstanding borrowings, $12.8 million in outstanding letters of credit and $677.2 million available for borrowing under the RCF. At December 31, 2014, the Partnership was in compliance with all covenants under the RCF.

The 2021 Notes, 2022 Notes, 2018 Notes, 2044 Notes and obligations under the RCF are recourse to the Partnership’s general partner. The Partnership’s general partner is indemnified by a wholly owned subsidiary of Anadarko, WGRI, against any claims made against the general partner under the 2022 Notes, 2021 Notes, and/or the RCF.

In connection with the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests, the Partnership’s general partner and other wholly owned subsidiaries of Anadarko entered into indemnification agreements, whereby such subsidiaries agreed to indemnify the Partnership’s general partner for any recourse liability it may have for RCF borrowings, or other debt financing, attributable to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests. These indemnification agreements apply to the 2044 Notes, 2018 Notes and/or RCF borrowings outstanding related to the aforementioned acquisitions.

The Partnership’s general partner, the other indemnifying subsidiaries of Anadarko and WGRI also amended and restated the indemnity agreements between them to (i) conform language among all the indemnification agreements and (ii) reduce the amount for which WGRI would indemnify the Partnership’s general partner by an amount equal to any amounts payable to the Partnership’s general partner under the indemnification agreements related to the acquisitions of the Non-Operated Marcellus Interest, the Anadarko-Operated Marcellus Interest and the TEFR Interests.

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12. DEBT AND INTEREST EXPENSE (CONTINUED)

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

	Year Ended December 31,		
thousands	2014	2013	2012
Third parties			
Interest expense on long-term debt	$81,495	$59,293	$41,171
Amortization of debt issuance costs and commitment fees	5,103	4,449	4,319
Capitalized interest	(9,832)	(11,945)	(6,196)
Total interest expense – third parties	76,766	51,797	39,294
Affiliates			
Interest expense on note payable to Anadarko [1]	—	—	2,440
Interest expense on affiliate balances [2]	—	—	326
Total interest expense – affiliates	—	—	2,766
Interest expense	$76,766	$51,797	$42,060

(1) In June 2012, the note payable to Anadarko was repaid in full. See Note payable to Anadarko within this Note 12.

(2) Imputed interest expense on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada complex and Lancaster plant. In the fourth quarter of 2012, the Partnership repaid the reimbursement payable to Anadarko associated with the construction of the Brasada complex and Lancaster plant.

13. COMMITMENTS AND CONTINGENCIES

Environmental obligations. The Partnership is subject to various environmental-remediation obligations arising from federal, state and local regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters. As of December 31, 2014 and 2013, asset retirement obligations and other on the consolidated balance sheets included $1.5 million and $1.9 million, respectively, of long-term liability for remediation and reclamation obligations. The recorded obligations do not include any anticipated insurance recoveries. The majority of payments related to these obligations are expected to be made over the next five years. Management regularly monitors the remediation and reclamation process and the liabilities recorded and believes that the amounts reflected in the Partnership’s recorded environmental obligations are adequate to fund remedial actions to comply with present laws and regulations, and that the ultimate liability for these matters, if any, will not differ materially from recorded amounts nor materially affect the Partnership’s overall results of operations, cash flows or financial condition. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered. See Note 10 and Note 11.

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

13. COMMITMENTS AND CONTINGENCIES (CONTINUED)

In July 2011, the Court denied the defendants' motion to dismiss without ruling on the merits. In August 2014, the judge scheduled a jury trial for July 2015. In preparation for trial, the parties amended their pleadings in October 2014 and are engaged in discovery and motion practice. Management does not believe the outcome of this proceeding will have a material effect on the Partnership's financial condition, results of operations or cash flows. The Partnership intends to vigorously defend this litigation. Furthermore, without regard to the merit of DCP's claims, management believes that the Partnership has adequate contractual indemnities covering the claims against it in this lawsuit.
In addition, from time to time, the Partnership is involved in legal, tax, regulatory and other proceedings in various forums regarding performance, contracts and other matters that arise in the ordinary course of business. Management is not aware of any such proceeding for which a final disposition could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Other commitments. The Partnership has short-term payment obligations, or commitments, related to its capital spending programs, as well as those of its unconsolidated affiliates. As of December 31, 2014, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $64.1 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to projects at the DJ Basin complex, which include the continued construction of Train II at the Lancaster plant and compressor expansions.

Lease commitments. Anadarko, on behalf of the Partnership, has entered into lease agreements for corporate offices, shared field offices and a warehouse supporting the Partnership's operations, for which Anadarko charges the Partnership rent. The leases for the corporate offices and shared field offices extend through 2017 and 2018, respectively, and the lease for the warehouse extends through February 2015.
Rent expense associated with the office, warehouse and equipment leases was $3.5 million, $2.8 million and $3.0 million for the years ended December 31, 2014, 2013 and 2012, respectively.
The amounts in the table below represent existing contractual operating lease obligations as of December 31, 2014, that may be assigned or otherwise charged to the Partnership pursuant to the reimbursement provisions of the omnibus agreement:

thousands	Operating Leases
2015	$338
2016	303
2017	157
2018	34
2019	—
Thereafter	—
Total	$832

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WESTERN GAS PARTNERS, LP
SUPPLEMENTAL QUARTERLY INFORMATION
(UNAUDITED)

The following table presents a summary of the Partnership's operating results by quarter for the years ended December 31, 2014 and 2013. The Partnership's operating results reflect the operations of the Partnership assets (as defined in Note 1—Summary of Significant Accounting Policies) from the dates of common control, unless otherwise noted. See Note 1—Summary of Significant Accounting Policies and Note 2—Acquisitions.

thousands except per-unit amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2014				
Revenues	$279,457	$329,944	$326,465	$337,897
Equity income, net	9,251	13,008	19,063	16,514
Operating income	100,158	115,133	123,374	112,922
Net income	91,127	98,482	106,540	94,409
Net income attributable to Western Gas Partners, LP	87,435	95,032	102,677	91,389
Net income per common unit – basic and diluted(1)	0.54	0.57	0.60	0.42
2013				
Revenues	$225,766	$251,402	$273,502	$279,093
Equity income, net	3,968	3,456	4,520	11,004
Operating income	64,023	69,859	90,209	96,767
Net income	52,945	61,876	81,882	88,740
Net income attributable to Western Gas Partners, LP	50,714	60,016	78,506	85,391
Net income per common unit – basic and diluted(1)	0.31	0.41	0.53	0.56

(1) Represents net income earned on and subsequent to the acquisition of the Partnership assets (as defined in Note 1—Summary of Significant Accounting Policies).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Chief Executive Officer and Chief Financial Officer of the Partnership's general partner performed an evaluation of the Partnership's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended ("Exchange Act"). Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Partnership's disclosure controls and procedures are effective as of December 31, 2014.

Changes in Internal Control Over Financial Reporting. There has been no change in our internal control over financial reporting during the quarter ended December 31, 2014, that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting. See Management's Assessment of Internal Control Over Financial Reporting under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

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PART III

Unless the context otherwise requires, references to “WES,” “we,” “us,” “our,” the “Partnership” or “Western Gas Partners” re to Western Gas Partners, LP and its subsidiaries. The Partnership’s general partner, Western Gas Holdings, LLC (the “general partner” or “GP”), is owned by Western Gas Equity Partners, LP (“WGP”), a Delaware master limited partnership formed by Anadarko Petroleum Corporation. Western Gas Equity Holdings, LLC (“WGP GP”) is WGP’s general partner and is a wholly owned subsidiary of Anadarko Petroleum Corporation. “Anadarko” refers to Anadarko Petroleum Corporation and its subsidiaries, excluding us and our general partner, and “affiliates” refers to subsidiaries of Anadarko, excluding us, and includes equity interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”), Enterprise EF78 LLC (the “Mont Belvieu JV”), Texas Express Pipeline LLC (“TEP”), Texas Express Gathering LLC (“TEG”) and Front Range Pipeline LLC (“FRP”). The interests in TEP, TEG and FRP are referred to collectively as the “TEFR Interests.”

Item 10. Directors, Executive Officers and Corporate Governance

Management of Western Gas Partners, LP

As a master limited partnership, we have no directors or officers. Instead, our general partner manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election in the future. The directors of our general partner oversee our operations. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. However, our general partner owes duties to our unitholders as defined and described in our partnership agreement. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Our general partner, therefore, may cause us to incur indebtedness or other obligations that are nonrecourse to it.

Our general partner’s Board of Directors has eight members, four of whom are independent as defined under the independence standards established by the New York Stock Exchange (“NYSE”) and the Securities Exchange Act of 1934, as amended (“Exchange Act”). The NYSE does not require a listed limited partnership, such as us, to have a majority of independent directors on the Board of Directors of our general partner or to establish a compensation committee or a nominating committee. Our general partner’s Board of Directors has affirmatively determined that Messrs. Steven D. Arnold, Milton Carroll, James R. Crane and David J. Tudor are independent as described in the rules of the NYSE and the Exchange Act. With respect to Mr. Crane, the Board specifically considered the transactions described under Item 13 of this Form 10-K. The Board determined that such transactions do not impact Mr. Crane’s independence. With respect to Mr. Arnold, the Board specifically considered that Mr. Arnold holds 13,600 shares of Anadarko stock. The Board determined that the ownership of these shares does not impact Mr. Arnold’s independence.

The executive officers of our general partner manage and conduct our day-to-day operations. The executive officers of our general partner allocate their time between managing our business and affairs and the business and affairs of Anadarko, and may face a conflict regarding the allocation of their time. We expect that the amount of time that the executive officers of our general partner devote to our business may increase or decrease in future periods as our business continues to develop. The executive officers of our general partner and other Anadarko employees operate our business and provide us with general and administrative services pursuant to the omnibus agreement and the services and secondment agreement described under Item 13 of this Form 10-K. We reimburse Anadarko for certain allocated expenses of operational personnel who perform services for our benefit, and for certain direct expenses.

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Board Leadership Structure

Through its ownership and control of WGP GP, Anadarko controls our general partner and, within the limitations of our partnership agreement and applicable U.S. Securities and Exchange Commission (“SEC”) and NYSE rules and regulations, also exercises broad discretion in establishing the governance provisions of our general partner’s limited liability company agreement. Accordingly, our general partner’s board structure is established by Anadarko. Although our general partner’s current board structure has separated the roles of Chairman and Chief Executive Officer (“CEO”), our general partner’s limited liability company agreement and Corporate Governance Guidelines permit the roles of Chairman and CEO to be combined. Anadarko may in the future combine those roles at its discretion.

Directors and Executive Officers

The biography of each director below contains information regarding that person’s service as a director, business experience, director positions held currently or at any time during the last five years, and involvement in certain legal or administrative proceedings, if applicable, and the experiences, qualifications, attributes or skills that caused our general partner and its Board of Directors to determine that the person should serve as a director of our general partner. In light of our strategic relationship with our sponsor, Anadarko, our general partner considers service as an Anadarko executive to be a meaningful qualification for service as a non-independent director of our general partner. The following table sets forth certain information with respect to the directors and executive officers of our general partner as of February 23, 2015. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	51	Chairman of the Board
Donald R. Sinclair	57	President, Chief Executive Officer and Director
Benjamin M. Fink	44	Senior Vice President, Chief Financial Officer and Treasurer
Jacqueline A. Dimpel	48	Senior Vice President (effective February 27, 2014)
Philip H. Peacock	43	Vice President, General Counsel and Corporate Secretary
Steven D. Arnold	54	Director
Milton Carroll	64	Director
James R. Crane	61	Director
Charles A. Meloy	54	Director
Robert K. Reeves	57	Director
David J. Tudor	55	Director

Our directors hold office until their successors are duly elected and qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the Board of Directors. There are no family relationships among any of our directors or executive officers.

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Robert G. Gwin Age: 51 Houston, Texas Director since: August 2007 Not Independent Officer From: August 2007 to January 2010	Biography/Qualifications Robert G. Gwin has served as a director of our general partner since August 2007 and has served as non-executive Chairman of the Board of our general partner since October 2009. He also served as Chief Executive Officer of our general partner from August 2007 to January 2010 and as President from August 2007 to September 2009. Mr. Gwin has served as Chairman of the Board of WGP GP since September 2012. He was named Executive Vice President, Finance and Chief Financial Officer of Anadarko in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer beginning in March 2009, prior to which he served as Senior Vice President of Anadarko beginning in March 2008, and as Vice President, Finance and Treasurer beginning in January 2006. Mr. Gwin is Chairman of the Board of LyondellBasell Industries N.V. and he also serves on the boards of The Greater Houston Partnership, Theatre Under the Stars and Communities in Schools. Mr. Gwin holds a Bachelor of Science degree from the University of Southern California and a Master of Business Administration degree from the Fuqua School of Business at Duke University, and he is a Chartered Financial Analyst.
Donald R. Sinclair Age: 57 Houston, Texas Director since: October 2009 Not Independent Officer Since: October 2009	Biography/Qualifications Donald R. Sinclair has served as President and a director of our general partner since October 2009 and as Chief Executive Officer since January 2010. Mr. Sinclair has served as the President and Chief Executive Officer and as a director of WGP GP since September 2012. He was named a Senior Vice President of Anadarko in May 2013, prior to which he served as a Vice President of Anadarko beginning in January 2010. Prior to joining Anadarko and becoming President and a director of our general partner, Mr. Sinclair was a founding partner and served as President of Ceritas Energy, LLC, a midstream energy company headquartered in Houston with operations in Texas, Wyoming and Utah from February 2003 to September 2009. Mr. Sinclair has worked in the oil and gas industry for over 33 years, with a focus on marketing and trading and the midstream sector. He is the Vice-Chairman of the Advisory Council for the Rawls College of Business at Texas Tech University. He earned a Bachelor of Business Administration in Management from Texas Tech University.
Benjamin M. Fink Age: 44 Houston, Texas Officer since: May 2009	Biography/Qualifications Benjamin M. Fink has served as the Senior Vice President and Chief Financial Officer of our general partner since May 2009, and as Senior Vice President, Chief Financial Officer and Treasurer of our general partner since November 2010. Mr. Fink has served as Senior Vice President, Chief Financial Officer and Treasurer of WGP GP since September 2012. He was Director, Finance of Anadarko from April 2007 to May 2009, during which time he was responsible for principal oversight of the finance operations of an Anadarko subsidiary, Anadarko Algeria Company, LLC. From August 2006 to April 2007, he served as an independent financial consultant to Anadarko in its Beijing, China and Rio de Janeiro, Brazil offices. From April 2001 until June 2006, he held executive management positions at Prosoft Learning Corporation, including serving as its President and Chief Executive Officer from November 2004 until that company's sale in June 2006. From 2000 to 2001 he co-founded and served as Chief Operating Officer and Chief Financial Officer of Meta4 Group Limited, an online direct marketer based in Hong Kong and Tokyo. Previously, he held positions of increasing responsibility at Prudential Capital Group and Prudential Asset Management Asia, where he focused on the negotiation, structuring and execution of private debt and equity

investments. He holds a Bachelor of Science degree in Economics from the Wharton School of the University of Pennsylvania, and he is a Chartered Financial Analyst.

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Jacqueline A. Dimpel Age: 48 Houston, Texas Officer since: February 2014	Biography/Qualifications Jacqueline A. Dimpel has served as Senior Vice President and principal operating officer for our general partner and for WGP GP since February 2014. She also has served as Vice President of Midstream for Anadarko since December 2013. Since joining Anadarko in 2006, Ms. Dimpel has served in a variety of technical, operational, and planning positions including Business Advisor for U.S. Onshore Operations and Midstream Operations Manager for the Southern and Appalachia region. Prior to joining Anadarko, Ms. Dimpel served in engineering roles of increasing responsibility with ExxonMobil. Ms. Dimpel holds a Bachelor of Science in Mechanical Engineering from The University of Notre Dame where she was accepted into Tau Beta Pi and Pi Tau Sigma Engineering Honor Societies. She is a professional licensed Mechanical Engineer in California and Texas and is a member of the Society of Petroleum Engineers. Ms. Dimpel serves on the Board of Directors of Texas Pipeline Association, as well as on the Board of Girl Scouts of San Jacinto Council.
Philip H. Peacock Age: 43 Houston, Texas Officer since: August 2012	Biography/Qualifications Philip H. Peacock has served as Vice President, General Counsel and Corporate Secretary of our general partner since August 2012. Mr. Peacock has served as Vice President, General Counsel and Corporate Secretary of WGP GP since September 2012. Prior to joining Western Gas, Mr. Peacock was a partner practicing corporate and securities law at the law firm of Andrews Kurth LLP, which he joined in August 2003. Mr. Peacock holds a Bachelor of Arts degree from Princeton University, a Master of Arts degree from the University of Houston, and a Juris Doctor degree from the University of Virginia. He is licensed to practice law in the state of Texas.
Steven D. Arnold Age: 54 Houston, Texas Director since: February 2014 Independent	Biography/Qualifications Steven D. Arnold was appointed as a director of our general partner and as a member of the Special Committee and Audit Committee of the Board of Directors of our general partner in February 2014. Mr. Arnold served on the Board of Directors of the general partner of Spectra Energy Partners, LP from 2007 to December 2013, during which time he served on that board’s Audit Committee and Conflicts Committee. He served as Chairman of each of those committees at separate times during his board membership. Mr. Arnold is engaged in private investment management and consulting services in Houston, Texas through 3 Lights Management Co., serving as its President since inception in 2000. Mr. Arnold has over ten years of institutional investment management experience with Prudential Financial, Inc. He is a board director of Houston Methodist Research Institute, Curing Children’s Cancer Fund, and chairs the Advisory Board of Texas Children’s Hospital Cancer Center. Mr. Arnold holds a Bachelor of Science Degree in Petroleum Engineering from the University of Texas at Austin and a Masters of Business Administration from Rice University. Mr. Arnold brings strong risk assessment and strategic expertise to the board.
Milton Carroll Age: 64 Houston, Texas Director since: April 2008 Independent	Biography/Qualifications Milton Carroll has served as a director of our general partner and as Chairman of the Special Committee of the Board of Directors of our general partner since April 2008. Mr. Carroll currently serves as Chairman of Houston-based CenterPoint Energy, Inc., where he has been a director since 1992. He also serves as Chairman of Health Care Services Corporation (a

Chicago-based company operating through its Blue Cross and Blue Shield divisions in Illinois, Texas, Oklahoma, New Mexico, and Montana), as a director of Halliburton Company, where he serves as a member of the Compensation Committee and the Nominating and Corporate Governance Committee, and as a director of LyondellBasell Industries N.V., where he serves as a member of the Nominating and Governance Committee and the Compensation Committee. Mr. Carroll served as a director of the general partner of LRR Energy, LP from November 2011 to January 2014. Mr. Carroll also served as a director of EGL, Inc. from May 2003 until August 2007 and as a director of the general partner of DCP Midstream Partners, LP from December 2005 to December 2006. Mr. Carroll holds a Bachelor of Science degree in Industrial Technology from Texas Southern University.

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James R. Crane Age: 61 Houston, Texas Director since: April 2008 Independent	Biography/Qualifications James R. Crane has served as a director of our general partner and as a member of the Special Committee and Audit Committee of the Board of Directors of our general partner since April 2008. In November 2011, Mr. Crane became the principal owner and Chairman of the Houston Astros Baseball Club. Mr. Crane is also the Chairman and Chief Executive Officer of Crane Capital Group Inc., an investment management company he founded. Crane Capital Group currently invests in transportation, power distribution, real estate and asset management. Its holdings include Crane Worldwide Logistics, a premier global provider of customized transportation and logistics services with 54 offices in 20 countries, and Champion Energy Services, a retail electric provider. Prior to founding Crane Capital Group Inc., he was founder, Chairman and Chief Executive Officer of EGL, Inc., a global transportation, supply chain management and information services company, from 1984 until its sale in August 2007. Mr. Crane currently serves as a director of Nabors Industries Ltd., an international drilling contractor and well-services provider. From February 2010 to February 2012, he served as a director of Fort Dearborn Life Insurance Company, a subsidiary of Health Care Service Corporation, and from 1999 to November 2007 he served as a director of HCC Insurance Holdings, Inc. Mr. Crane holds a Bachelor of Science degree in Industrial Safety from the University of Central Missouri.
Charles A. Meloy Age: 54 Houston, Texas Director since: February 2009 Not Independent	Biography/Qualifications Charles A. Meloy has served as a director of our general partner since February 2009 and as a director of WGP GP since September 2012. Mr. Meloy was named Executive Vice President, U.S. Onshore Exploration and Production of Anadarko in May 2013, and previously served as Senior Vice President, U.S. Onshore Exploration and Production beginning in July 2012, prior to which he served as Senior Vice President, Worldwide Operations beginning in December 2006. Before joining Anadarko, he served as Vice President of Exploration and Production at Kerr-McGee Corporation, prior to its acquisition by Anadarko. At Kerr-McGee, Mr. Meloy was Vice President of Gulf of Mexico exploration, production and development from 2004 to 2005, was Vice President and Managing Director of North Sea operations from 2002 to 2004, and held several other deepwater Gulf of Mexico management positions beginning in 1999. Earlier in his career, Mr. Meloy held various planning, operations, deepwater and reservoir engineering positions with Oryx Energy Company and its predecessor, Sun Oil Company. He earned a Bachelor's degree in Chemical Engineering from Texas A&M University and is a member of the Society of Petroleum Engineers and Texas Professional Engineers. Mr. Meloy is also a member of the Board of Directors of the Independent Producers of America Association.
Robert K. Reeves Age: 57 Houston, Texas Director since: August 2007 Not Independent	Biography/Qualifications Robert K. Reeves has served as a director of our general partner since August 2007 and as a director of WGP GP since September 2012. Mr. Reeves was named Executive Vice President, General Counsel and Chief Administrative Officer of Anadarko in May 2013 and previously served as Senior Vice President, General Counsel and Chief Administrative Officer beginning in February 2007, prior to which he served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer of Anadarko beginning in 2004. He has also served as a director of Key Energy Services, Inc., a publicly traded oil field services company, since October 2007. Prior to joining Anadarko, he served as Executive Vice President,

Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. Mr. Reeves holds a Bachelor of Science degree in Business Administration and a Juris Doctor degree from Louisiana State University.

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	Biography/Qualifications
David J. Tudor Age: 55 Houston, Texas Director since: April 2008 Independent	David J. Tudor has served as a director of our general partner and as Chairman of the Audit Committee of the Board of Directors of our general partner since April 2008, and previously served as a member of the Special Committee of the Board of Directors of our general partner from April 2008 to December 2012. Mr. Tudor has served as a director of WGP GP and as Chairman of the Audit Committee of its Board of Directors since December 2012. Since May 2013, Mr. Tudor has served as President and Chief Executive Officer of Champion Energy Services, a retail electric provider serving residential, governmental, commercial and industrial customers in a growing number of deregulated electric energy markets throughout the United States. From 1999 through May 2013, Mr. Tudor was the President and Chief Executive Officer of ACES, an Indianapolis-based commodity risk management company owned by 21 generation and transmission cooperatives throughout the United States. Prior to joining ACES, Mr. Tudor was the Executive Vice President & Chief Operating Officer of PG&E Energy Trading, where he managed commercial operations in the United States and Canada. Mr. Tudor holds a Bachelor of Science degree in Accounting from David Lipscomb University.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's directors and executive officers, and persons who own more than 10 percent of a registered class of our equity securities, to file with the SEC, and any exchange or other system on which such securities are traded or quoted, initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater-than-10-percent unitholders are required by the SEC's regulations to furnish to us, and any exchange or other system on which such securities are traded or quoted, with copies of all Section 16(a) forms they file with the SEC.
To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our general partner's officers, directors and greater-than-10-percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2014, except that on February 10, 2015, a late Form 5 was filed with respect to certain changes in Mr. Sinclair's ownership of common units.

Reimbursement of Expenses of Our General Partner and Its Affiliates

Our general partner does not receive any management fee or other compensation for its management of our Partnership under the omnibus agreement, the services and secondment agreement or otherwise. Under our partnership and omnibus agreements, we reimburse Anadarko for general and administrative expenses allocated, as determined by Anadarko in its reasonable discretion. Please read Item 13 of this Form 10-K for additional information regarding these agreements.

Board Committees

The Board of Directors of our general partner has two standing committees: the Audit Committee and the Special Committee.

Audit Committee

The Audit Committee is comprised of three independent directors, Messrs. Tudor (Chairman), Arnold and Crane, each of whom is able to understand fundamental financial statements and at least one of whom has past experience in accounting or related financial management experience. The Board has determined that each member of the Audit

Committee is independent under the NYSE listing standards and the Exchange Act. In making the independence determination, the Board considered the requirements of the NYSE and our Code of Business Conduct and Ethics. The Audit Committee held five meetings in 2014.

Mr. Tudor has been designated by the Board of Directors of our general partner as the “Audit Committee financial expert” meeting the requirements promulgated by the SEC based upon his education and employment experience as more fully detailed in Mr. Tudor’s biography set forth above.

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The Audit Committee assists the Board of Directors in its oversight of the integrity of our consolidated financial statements, our internal controls over financial reporting, and our compliance with legal and regulatory requirements and Partnership policies and controls. The Audit Committee has the sole authority to, among other things, (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) establish policies and procedures for the pre-approval of all audit, audit-related, non-audit and tax services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the Audit Committee and to our management, as necessary.

Special Committee

The Special Committee is comprised of three independent directors, Messrs. Carroll (Chairman), Arnold, and Crane. The Special Committee reviews specific matters that the Board believes may involve conflicts of interest (including certain transactions with Anadarko). The Special Committee will determine, as set forth in the partnership agreement, if the resolution of a conflict of interest submitted to it is fair and reasonable to us. The members of the Special Committee are not officers or employees of our general partner or directors, officers, or employees of its affiliates, including Anadarko. Our partnership agreement provides that any matters approved in good faith by the Special Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. The Special Committee held three meetings in 2014.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of our general partner's Board of Directors, all of our independent directors meet in an executive session without management participation or participation by non-independent directors. Mr. Carroll, the Chairman of the Special Committee, presides over these executive sessions.
The general partner's Board of Directors welcomes questions or comments about the Partnership and its operations. Unitholders or interested parties may contact the Board of Directors, including any individual director, at boardofdirectors@westerngas.com or at the following address and fax number: Name of the Director(s), c/o Corporate Secretary, Western Gas Partners, LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, (832) 636-6001.

Code of Ethics, Corporate Governance Guidelines and Board Committee Charters

Our general partner has adopted a Code of Ethics for CEO and Senior Financial Officers (the "Code of Ethics"), which applies to our general partner's Chief Executive Officer, Chief Financial Officer, principal accounting officer, Controller and all other senior financial and accounting officers of our general partner. If the general partner amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, we will disclose the information on our website. Our general partner has also adopted Corporate Governance Guidelines that outline the important policies and practices regarding our governance and a Code of Business Conduct and Ethics applicable to all employees of Anadarko or affiliates of Anadarko who perform services for us and our general partner.
We make available free of charge, within the "Investor Relations" section of our website at www.westerngas.com, and in print to any unitholder who so requests, our Code of Ethics, Corporate Governance Guidelines, Code of Business Conduct and Ethics, Audit Committee charter and Special Committee charter. Requests for print copies may be directed to investors@westerngas.com or to: Investor Relations, Western Gas Partners LP, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, or telephone (832) 636-6000. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

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Item 11. Executive Compensation

COMPENSATION DISCUSSION AND ANALYSIS

Overview

We do not directly employ any of the persons responsible for managing our business, and our general partner's Board of Directors does not have a compensation committee. The compensation of Anadarko's employees that perform services on our behalf, including our executive officers, is approved by Anadarko's management, other than long-term incentive compensation under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the "WES LTIP") and the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan (the "WGP LTIP"). When used in the mix of compensation for our named executive officers, awards under the WES LTIP and WGP LTIP are recommended by Anadarko's management and approved by the Board of Directors of our general partner, or the Board of Directors of WGP GP, as applicable. Our reimbursement to Anadarko for the compensation of executive officers is governed by the omnibus agreement. Under our partnership and omnibus agreements, we reimburse general and administrative expenses as determined by Anadarko in its reasonable discretion. Please read the caption Omnibus Agreement under Item 13 of this Form 10-K.

Our "named executive officers" for 2014 were Donald R. Sinclair (the principal executive officer), Benjamin M. Fink (the principal financial officer and principal accounting officer), Jacqueline A. Dimpel (the principal operating officer; appointed February 27, 2014) and Philip H. Peacock (the vice president, general counsel and corporate secretary). Compensation paid or awarded by us in 2014 with respect to the named executive officers reflects only the portion of compensation expense that is allocated to us pursuant to Anadarko's allocation methodology and subject to the terms of the omnibus agreement. Anadarko has the ultimate decision-making authority with respect to the total compensation of the named executive officers and, subject to the terms of the omnibus agreement, the portion of such compensation we reimburse pursuant to Anadarko's allocation methodology. Generally, once Anadarko has established the aggregate amount to be paid or awarded to the named executive officers with respect to each element of compensation for services rendered to both our general partner and Anadarko, such aggregate amount is multiplied by an allocation percentage for each named executive officer. Each allocation percentage is established based on a periodic, good-faith estimate made by each named executive officer and is subject to review by the Chairman of our general partner's Board of Directors. The resulting amount (other than with respect to certain long-term incentive plan awards) is the amount reimbursed to Anadarko by us pursuant to the terms of the omnibus agreement and appears in the Summary Compensation Table below. Notwithstanding the foregoing, perquisites are not currently allocated to us, and bonus amounts under the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table are capped consistent with the methodology set forth in the services and secondment agreement for all employees whose compensation is allocated to us.

The following table presents the estimated percentage of time ("time allocation") that the general partner's named executive officers devoted to the Partnership during the year ended December 31, 2014, which percentage represents the time devoted to the business of the Partnership relative to time devoted to the businesses of the Partnership and Anadarko in the aggregate:

Officers of Our General Partner	Time Allocated	Anadarko Corporate Officer
Donald R. Sinclair	75.0%	Yes
Benjamin M. Fink	90.0%	Yes
Jacqueline A. Dimpel	25.0%	Yes
Philip H. Peacock	50.0%	No

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The following discussion relating to compensation paid by Anadarko is based on information provided to us by Anadarko and does not purport to be a complete discussion and analysis of Anadarko's executive compensation philosophy and practices. For a more complete analysis of the compensation programs and philosophies used at Anadarko, please read Compensation Discussion and Analysis contained within Anadarko's proxy statement, which is expected to be filed with the SEC no later than April 2, 2015. With the exception of grants that could be made under the WES LTIP and WGP LTIP, the elements of compensation discussed below (and Anadarko's decisions with respect to the levels of such compensation) are not subject to approvals by the WES Board of Directors or WGP Board of Directors, as applicable, including the Audit or Special Committees thereof.

Elements of Compensation

The primary elements of Anadarko's compensation program are a combination of annual cash and long-term equity-based compensation. For 2014, the principal elements of compensation for the named executive officers were as follows:

- base salary;
- annual cash incentives;
- equity-based compensation, which includes equity-based compensation under Anadarko's 2012 Omnibus Incentive Compensation Plan (the "Omnibus Plan"); and
- Anadarko's other benefits, including welfare and retirement benefits, severance benefits and change of control benefits, plus other benefits on the same basis as other eligible Anadarko employees.

Base salary. Anadarko's management establishes base salaries to provide a fixed level of income for our named executive officers for their level of responsibility (which may or may not be related to our business), their relative expertise and experience, and in some cases their potential for advancement. As discussed above, a portion of the base salaries of our named executive officers is allocated to us based on Anadarko's methodology used for allocating general and administrative expenses.

Annual cash incentives (bonuses). Anadarko's management will make annual cash awards to our named executive officers in 2015 for their performance during the year ended December 31, 2014, under the 2014 Anadarko annual incentive program ("AIP"), which is administered under the Omnibus Plan. Annual cash incentive awards are used by Anadarko to motivate and reward its executives and employees for the achievement of Anadarko objectives aligned with value creation and/or to recognize individual contributions to Anadarko's performance. The AIP puts a portion of an executive's compensation at risk by linking potential annual compensation to Anadarko's achievement of specific performance metrics during the year related to operational, financial and safety measures internal to Anadarko. The AIP bonuses paid to our named executive officers were determined by Anadarko's management.
The portion of any annual cash awards allocable to us is based on Anadarko's methodology used for allocating general and administrative expenses, subject to the limitations established in the omnibus agreement. Anadarko's general policy is to pay these awards during the first quarter of each calendar year for the prior year's performance.

Long-term incentive awards under the Omnibus Plan. Anadarko periodically makes equity-based awards under the Omnibus Plan to align the interests of its executive officers and employees with those of Anadarko stockholders by emphasizing the long-term growth in Anadarko's value. For 2014, the annual equity awards generally consisted of a combination of (1) stock options, (2) time-based restricted stock units or shares of restricted stock and (3) performance units. This award structure is intended to provide a combination of equity-based vehicles that is performance-based in absolute and relative terms, while also encouraging retention. The costs allocated to us for the named executive officers' compensation includes an allocation of expense associated with a portion of these awards in accordance with the allocation mechanisms in the omnibus agreement.

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Other benefits. In addition to the compensation discussed above, Anadarko also provides other benefits to the named executive officers who are also Anadarko corporate vice presidents, including the following:

- retirement benefits to match competitive practices in Anadarko's industry, including participation in Anadarko's employee savings plan, savings restoration plan, retirement plan and retirement restoration plan;
- severance benefits under the Anadarko Officer Severance Plan;
- certain change of control benefits under key employee change of control contracts;
- director and officer indemnification agreements;
- a limited number of perquisites, including financial counseling, tax preparation and estate planning, an executive physical program, management life insurance, voluntary participation in the Deferred Compensation Plan, and personal excess liability insurance; and
- benefits, including medical, dental, vision, flexible spending and health savings accounts, paid time off, life insurance and disability coverage, which are also provided to all other eligible U.S.-based Anadarko employees.

For a more detailed summary of Anadarko's executive compensation program and the benefits provided thereunder, please read Compensation Discussion and Analysis contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed with the SEC no later than April 2, 2015.

Role of Executive Officers in Executive Compensation

Anadarko's management determines a significant part of the compensation for each of our named executive officers. The Board of Directors of our general partner determines compensation for the independent, non-management directors of our general partner's Board of Directors, as well as any grants made under the WES LTIP. None of our named executive officers provides compensation recommendations to the Anadarko Compensation and Benefits Committee or Anadarko's management team regarding compensation (other than recommendations with respect to employees that report directly to them).

Compensation Mix

We believe that the mix of base salary, cash awards, equity-based awards under Anadarko's Omnibus Plan, other Anadarko compensation and, when utilized, the WES LTIP and WGP LTIP, fit Anadarko's and our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies, as well as Anadarko's, and to attract, motivate and retain high-quality talent with the skills and competencies required by us and Anadarko. For 2014, Anadarko's management determined that equity compensation awarded to our executive officers would not include grants under the WES LTIP or WGP LTIP.

Western Gas Partners, LP 2008 Long-Term Incentive Plan

General. In April 2008, our general partner adopted the WES LTIP for employees and directors of our general partner and its affiliates, including Anadarko, who perform services for us. The summary of the WES LTIP contained herein does not purport to be complete and is qualified in its entirety by reference to the WES LTIP, the terms of which have been previously filed with the SEC. The WES LTIP provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights ("UARs"), distribution equivalent rights ("DERs") and substitute awards.

Subject to adjustment for certain events, an aggregate of 2,250,000 common units may be delivered pursuant to awards under the WES LTIP. Units that are cancelled, forfeited or are withheld to satisfy tax withholding obligations or payment of an award's exercise price are available for delivery pursuant to other awards. The WES LTIP is administered by our general partner's Board of Directors. The WES LTIP has been designed to promote the interests of the Partnership and its unitholders by strengthening its ability to attract, retain and motivate qualified individuals to serve as directors and employees.

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WES unit awards. Our general partner’s Board of Directors may grant unit awards to eligible individuals under the WES LTIP. A unit award is an award of common units that are fully vested upon grant and are not subject to forfeiture. No unit awards were granted during 2014.

WES restricted units and phantom units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is no longer subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of our general partner’s Board of Directors, cash equal to the market value of a common unit on the vesting date. Our general partner’s Board of Directors may make grants of restricted and phantom units under the WES LTIP that contain such terms, consistent with the WES LTIP, as the Board may determine are appropriate, including the period over which restricted or phantom units will vest. The Board may, in its discretion, base vesting on the grantee’s completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and phantom units will vest automatically upon a change of control of our general partner (as defined in the WES LTIP) or as otherwise described in the award agreement.
If a grantee’s employment or membership on the Board of Directors terminates for any reason, the grantee’s restricted and phantom units will be automatically forfeited unless and to the extent that the award agreement or the Board provides otherwise.
Distributions made by us with respect to awards of restricted units may, in the Board’s discretion, be subject to the same vesting requirements as the restricted units. The Board, in its discretion, may also grant tandem DERs with respect to phantom units.
No restricted or phantom units were granted to our named executive officers during 2014.

WES unit options and unit appreciation rights. The WES LTIP also permits the grant of options covering common units and UARs. Unit options represent the right to purchase a number of common units at a specified exercise price. UARs represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units as determined by the Board. Unit options and UARs may be granted to such eligible individuals and with such terms as the Board may determine, consistent with the WES LTIP; however, a unit option or UAR must have an exercise price greater than or equal to the fair market value of a common unit on the date of grant. No unit options or UARs were granted during 2014.

WES distribution equivalent rights. DERs are rights to receive all or a portion of the distributions otherwise payable on units during a specified time. DERs may be granted alone or in combination with another award. No WES DERs, whether tandem to other awards or stand-alone, were issued to our named executive officers during 2014.

Source of WES common units. Common units to be delivered with respect to awards may be newly issued units, common units acquired by our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us or any other person, or any combination of the foregoing. If our general partner acquires units in the open market, it is entitled to reimbursement by us for the cost incurred in acquiring such common units. With respect to unit options, our general partner is entitled to reimbursement from us for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from an optionee at the time of exercise. Thus, we bear the cost of the unit options. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our general partner is entitled to reimbursement by us for the amount of the cash settlement.

Amendment or termination of WES LTIP. Our general partner’s Board of Directors, in its discretion, may terminate the WES LTIP at any time with respect to the common units for which a grant has not previously been made. The WES LTIP will automatically terminate on the earlier of the 10th anniversary of the date it was initially adopted by our general partner or when common units are no longer available for delivery pursuant to awards under the WES LTIP. Our general partner’s Board of Directors will also have the right to alter or amend the WES LTIP or any part of it from time to time or to amend any outstanding award made under the WES LTIP; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant, and/or result in taxation to the participant under Section 409A of the Internal Revenue Code of 1986, as amended, unless otherwise determined by the general partner’s Board of Directors.

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Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan

General. In November 2012, WGP GP adopted the WGP LTIP for its employees and directors and those of its affiliates who perform services for us. The WGP LTIP consists of the following components: restricted units, phantom units, unit options, UARs, other unit-based awards, cash awards, unit awards, substitute awards and DERs. The WGP LTIP limits the number of units that may be delivered pursuant to awards to 3,000,000 units. Units withheld to satisfy exercise prices or tax withholding obligations are available for delivery pursuant to other awards. The WGP LTIP is administered by the Board of Directors of WGP GP.
The Board of Directors of WGP GP may terminate or amend the WGP LTIP at any time with respect to any units for which a grant has not yet been made. The Board of Directors of WGP GP also has the right to alter or amend the WGP LTIP or any part of the plan from time to time, including increasing the number of units that may be granted subject to WGP unitholder approval as may be required by the exchange upon which the WGP common units are listed at that time, if any. However, no change in any outstanding grant may be made that would materially reduce the benefits of the participant without the consent of the participant. The WGP LTIP will expire upon the earlier of the 10th anniversary of its adoption, its termination by the WGP GP Board of Directors or when no units remain available under the plan for awards. Awards then outstanding will continue pursuant to the terms of their grants.

WGP restricted units. A restricted unit is a grant of a WGP common unit subject to a risk of forfeiture, performance conditions, restrictions on transferability, and any other restrictions imposed by the plan administrator in its discretion. Restrictions may lapse at such times and under such circumstances as determined by the plan administrator. The plan administrator shall provide, in the restricted unit agreement, whether the restricted unit will be forfeited upon certain terminations of employment and whether the restricted unit will receive DERs. Except as otherwise determined by the plan administrator in the award agreement or otherwise, all outstanding unvested restricted units will be forfeited upon termination of a participant’s service. Cash distribution equivalents may be paid during or after the vesting period with respect to a restricted unit, as determined by the plan administrator. No WGP restricted units were granted during 2014.

WGP phantom units. Phantom units are rights to receive WGP common units, cash, or a combination of both at the end of a specified period. The plan administrator may subject phantom units to restrictions (which may include a risk of forfeiture) to be specified in the phantom unit agreement that may lapse at such times determined by the plan administrator. Phantom units may be satisfied by delivery of WGP common units, cash equal to the fair market value of the specified number of WGP common units covered by the phantom unit, or any combination thereof determined by the plan administrator. Except as otherwise provided by the plan administrator in the phantom unit agreement or otherwise, all outstanding unvested phantom units will be forfeited upon termination of a participant’s service. Cash distribution equivalents may be paid during or after the vesting period with respect to a phantom unit, as determined by the plan administrator. No WGP phantom units were granted to our named executive officers during 2014.

WGP options. Option awards are options to acquire WGP common units at a specified price. The exercise price of each option granted under the WGP LTIP will be stated in the option agreement and may vary; provided, however, that, the exercise price for an option must not be less than 100% of the fair market value per WGP common unit as of the date of grant of the option unless that option is intended to otherwise comply with the requirements of Section 409A of the Code. Options may be exercised in the manner and at such times as the plan administrator determines for each option, unless that option is determined to be subject to Section 409A of the Code, where the option will be subject to any necessary timing restrictions imposed by the Code or federal regulations. The plan administrator will determine the methods and form of payment for the exercise price of an option and the methods and forms in which WGP common units will be delivered to a participant. Except as otherwise provided by the plan administrator in the award agreement or otherwise, all unvested options will be forfeited upon termination of a participant’s service. No WGP options were granted during 2014.

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WGP unit appreciation rights. A UAR is the right to receive, in cash or in WGP common units, as determined by the plan administrator, an amount equal to the excess of the fair market value of one WGP common unit on the date of exercise over the grant price of the UAR. The plan administrator will be able to make grants of UARs and will determine the time or times at which a UAR may be exercised in whole or in part. The exercise price of each UAR granted under the WGP LTIP will be stated in the UAR agreement and may vary; provided, however, that the exercise price must not be less than 100% of the fair market value per WGP common unit as of the date of grant of the UAR unless that UAR Award is intended to otherwise comply with the requirements of Section 409A of the Code. Except as otherwise provided by the plan administrator in the award agreement or otherwise, all unvested UARs will be forfeited upon termination of a participant's service. No WGP UARs were granted during 2014.

WGP unit awards. The plan administrator is authorized to grant WGP common units that are not subject to restrictions. The plan administrator may grant unit awards to any eligible person in such amounts as the plan administrator, in its sole discretion, may select. No WGP unit awards were granted during 2014.

WGP substitute awards. The WGP LTIP permits the grant of awards in substitution for similar awards held by individuals who become employees or directors as a result of a merger, consolidation or acquisition by us, an affiliate of another entity or the assets of another entity. Such substitute awards that are options or UARs may have exercise prices less than 100% of the fair market value per WGP common unit on the date of the substitution if such substitution complies with Section 409A of the Code and its regulations, and other applicable laws and exchange rules. No WGP substitute awards were granted during 2014.

Other WGP unit-based awards. The WGP LTIP permits the grant of other unit-based awards, which are awards that may be based, in whole or in part, on the value or performance of a WGP common unit or are denominated or payable in WGP common units. Upon settlement, the unit-based award may be paid in WGP common units, cash or a combination thereof, as provided in the award agreement. No other WGP unit-based awards were granted during 2014.

WGP cash awards. The WGP LTIP permits the grant of awards denominated in and settled in cash. Cash awards may be based, in whole or in part, on the value or performance of a WGP common unit. No WGP cash awards were granted during 2014.

WGP distribution equivalent rights. The plan administrator is able to grant DERs in tandem with awards under the WGP LTIP (other than an award of restricted units or unit awards), or they may be granted alone. DERs entitle the participant to receive cash equal to the amount of any cash distributions made by us during the period the DER is outstanding. Payment of a DER issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the plan administrator. No WGP DERs were granted to our named executive officers during 2014.

WGP performance awards. The plan administrator may condition the right to exercise or receive an award under the WGP LTIP, or may increase or decrease the amount payable with respect to an award, based on the attainment of one or more performance conditions deemed appropriate by the plan administrator. No WGP performance awards were granted during 2014.

Tax withholding. At the plan administrator's discretion, subject to conditions that it may impose, a participant's minimum statutory tax withholding with respect to an award may be satisfied by withholding from any payment related to an award or by the withholding of WGP common units issuable pursuant to the award based on the fair market value of the WGP common units.

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EXECUTIVE COMPENSATION

As noted above, we do not directly employ any of the persons responsible for managing or operating our business and we have no compensation committee. Instead, we are managed by our general partner, the executive officers of which are employees of Anadarko. Our reimbursement for the compensation of executive officers is governed by the omnibus agreement and the services and secondment agreement described in the caption Agreements with Anadarko—Services and Secondment Agreement under Item 13 of this Form 10-K.

Summary Compensation Table

The following table summarizes the compensation amounts expensed by us for our named executive officers for the years ended December 31, 2014, 2013 and 2012, as applicable. Except as specifically noted, the amounts included in the table below reflect the expense allocated to us by Anadarko. For a discussion of the allocation percentages in effect for 2014, please see the Overview section, above.

Name and Principal Position	Year	Salary ($) [1]	Bonus ($)	Stock Awards ($) [2]	Option Awards ($) [3]	Non-Equity Incentive Plan Compensation ($) [4]	All Other Compensation ($) [5]	Total ($)
Donald R. Sinclair	2014	304,327	—	807,851	436,272	292,154	77,370	1,917,974
President and	2013	283,414	—	843,813	280,588	243,736	123,110	1,774,661
Chief Executive Officer	2012	271,298	—	506,296	168,623	—	113,250	1,059,467
Benjamin M. Fink	2014	300,635						