Western Gas Partners LP
Form 10-K
February 28, 2014
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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, 2013

Or

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

For the transition period from to

Commission file number: 001-34046

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the registrant's common units representing limited partner interests held by non-affiliates of the registrant was $4.0 billion on June 28, 2013, based on the closing price as reported on the New York Stock Exchange.

At February 24, 2014, there were 117,624,092 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.
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.
Long ton: A British unit of weight equivalent to 2,240 pounds.
LTD: Long tons per day.

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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.
Re-frac: The repeated process of hydraulic fracturing.
Residue: The natural gas remaining after being 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 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 terms 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 master limited partnership formed by Anadarko 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 consolidated subsidiaries, excluding the Partnership and the general partner, and “affiliates” refers to wholly owned and partially owned 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”), and Enterprise EF78 LLC (the “Mont Belvieu JV”). “Equity investment throughput” refers to our 14.81% share of Fort Union and 22% share of Rendezvous gross volumes. “MIGC” refers to MIGC LLC, and “Chipeta” refers to Chipeta Processing LLC. The Partnership and its subsidiaries are indirect subsidiaries of Anadarko.

Available information. We electronically file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents with the U.S. Securities and Exchange Commission (“SEC”) under the Securities Exchange Act of 1934. 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 Internet 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 Internet 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 Internet 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, 2013, our assets, exclusive of our interests in Fort Union, White Cliffs, Rendezvous and the Mont Belvieu JV accounted for under the equity method, consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests
Natural gas gathering systems	13	1	5
Natural gas treating facilities	8	—	—
Natural gas processing facilities	8	3	—
NGL pipelines	3	—	—
Natural gas pipelines	3	—	—

These assets are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), north-central Pennsylvania, and East, South and West Texas. The following table provides information regarding our assets by geographic region, excluding our Lancaster processing plant under construction in Northeast Colorado, as of and for the year ended December 31, 2013:

Area	Asset Type	Miles of Pipeline	Approximate Number of Receipt Points	Gas Compression (Horsepower)	Processing or Treating Capacity (MMcf/d) (1)	Average Gathering, Processing and Transportation Throughput (MMcf/d) (2)
Rocky Mountains	Gathering, Processing and Treating	7,194	5,074	401,457	2,780	2,284
	Transportation	1,192	25	30,002	—	79
Mid-Continent	Gathering	2,053	1,505	92,097	—	73
North-central Pennsylvania	Gathering	530	306	70,750	—	616
East Texas	Gathering and Treating	594	846	37,605	502	218
South and West Texas	Gathering, Processing and Treating	189	87	—	200	98
Total		11,752	7,843	631,911	3,482	3,368

(1) Capacity excludes 170 MBbls/d of fractionation capacity.

(2) Throughput includes 100% of Chipeta volumes, 50% of Newcastle volumes, 22% of Rendezvous volumes and 14.81% of Fort Union volumes. Throughput excludes 22 MBbls/d of average NGL pipeline volumes, 7 MBbls/d of average oil pipeline volumes representing our 10% share of average White Cliffs volumes, and 8 MBbls/d of average fractionated volumes representing our 25% share of average Mont Belvieu JV volumes. 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 U.S. See Item 8 of this Form 10-K for disclosure of revenues, profits and total assets for the years ended December 31, 2013, 2012 and 2011.

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ACQUISITIONS

Acquisitions. The following table presents our acquisitions during 2013, and identifies the funding sources for such acquisitions. See Note 2—Acquisitions and Note 12—Subsequent Events 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	GP Units Issued
Non-Operated Marcellus Interest [1]	03/01/2013	33.75	%	$250,000	$215,500	449,129	—
Anadarko-Operated Marcellus Interest [2]	03/08/2013	33.75	%	133,500	—	—	—
Mont Belvieu JV [3]	06/05/2013	25	%	—	78,129	—	—
OTTCO [4]	09/03/2013	100	%	27,500	—	—	—

(1) We acquired Anadarko's 33.75% interest (non-operated) in the Liberty and Rome gas gathering systems, serving production from the Marcellus shale in north-central Pennsylvania. The interest acquired is referred to as the "Non-Operated Marcellus Interest." In connection with the issuance of the common units, our general partner purchased 9,166 general partner units for consideration of $0.5 million in order to maintain its 2.0% general partner interest in us.

(2) We acquired a 33.75% interest in each of the Larry's Creek, Seely and Warrensville gas gathering systems, which are operated by Anadarko and serve production from the Marcellus shale in north-central Pennsylvania, from a third party. The interest acquired is referred to as the "Anadarko-Operated Marcellus Interest."

(3) We acquired a 25% interest in Enterprise EF78 LLC, an entity formed to design, construct, and own two fractionators located in Mont Belvieu, Texas, from a third party. The interest acquired is accounted for under the equity method of accounting.

(4) We acquired Overland Trail Transmission, LLC ("OTTCO"), a Delaware limited liability company, from a third party. OTTCO owns and operates an intrastate pipeline that connects our Red Desert and Granger complexes in southwestern Wyoming.

Presentation of Partnership assets. References to the "Partnership assets" refer collectively to the assets owned by us as of December 31, 2013. Because Anadarko controls us through its control of WGP, which owns our general partner, each of our acquisitions of 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 assets from Anadarko, we may be required to recast our financial statements to include the activities of such assets as of the date of common control.

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EQUITY OFFERINGS

Equity offerings. We completed the following public equity offerings during 2013:

thousands except unit and per-unit amounts	Common Units Issued (1)	GP Units Issued (2)	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
May 2013 equity offering	7,015,000	143,163	$61.18	$13,203	$424,733
December 2013 equity offering (3)	4,500,000	91,837	61.51	8,716	273,728

(1) Includes the issuance of 915,000 common units pursuant to the full exercise of the underwriters' over-allotment option granted in connection with the May 2013 equity offering.

(2) Represents general partner units issued to the general partner in exchange for the general partner's proportionate capital contribution to maintain its 2.0% general partner interest.

(3) Excludes the issuance of 300,000 common units on January 3, 2014, pursuant to the partial exercise of the underwriters' over-allotment option, and the corresponding issuance of 6,122 general partner units to the general partner in exchange for the general partner's proportionate capital contribution to maintain its 2.0% general partner interest. Total net proceeds for the partial exercise of the underwriters' over-allotment option (including the general partner's proportionate capital contribution) were $18.3 million.

Pursuant to our registration statement filed with the SEC in August 2012 authorizing the issuance of up to an aggregate of $125.0 million of common units (the "Continuous Offering Program"), during the three months ended December 31, 2013, we completed trades totaling 642,385 common units, at an average price per unit of $60.83, generating gross proceeds of $39.9 million (including the general partner's proportionate capital contribution and before $0.9 million of associated offering expenses). During the year ended December 31, 2013, we completed trades totaling 685,735 common units at an average price per unit of $60.84, generating gross proceeds of $42.6 million (including the general partner's proportionate capital contribution and before $1.0 million of associated offering expenses).

Other equity offerings. In March 2013, as partial consideration for our acquisition of the Non-Operated Marcellus Interest, we issued 449,129 common units to Anadarko Marcellus Midstream, L.L.C., ("AMM"), a subsidiary of Anadarko, at an implied price of $54.55 per common unit. In addition, please refer to Note 12—Subsequent Events 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 commodity price uncertainty through the use of fee-based contracts and fixed-price hedges.

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- 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 help pursue projects that help to enhance the value of our business. See Our Relationship with Anadarko Petroleum Corporation below.
- Relatively stable and predictable cash flows. Our cash flows are largely protected from fluctuations caused by commodity price volatility due to (i) the approximately three-fourths 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 our percent-of-proceeds and keep-whole contracts. For the year ended December 31, 2013, 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.
- 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, 2013, we had no outstanding borrowings under our $800.0 million senior unsecured revolving credit facility (“RCF”), and we had $12.8 million in outstanding letters of credit issued under the RCF.
- Substantial presence in basins with strong producer economics. Our portfolio includes midstream assets located in major onshore producing basins in Wyoming, Colorado, Utah, Kansas, Oklahoma, Pennsylvania, and Texas. Our interests in the Anadarko-Operated and Non-Operated Marcellus gathering systems serve dry gas production from the Marcellus shale, which provides 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. In addition, our Wattenberg, Platte Valley, and Brasada assets 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. NGL prices have historically been correlated to crude oil prices as opposed to natural gas prices. Due to the relatively high current price of crude oil as compared to natural gas, production in these areas offers our customers higher margins and superior economics compared to basins in which the gas is predominantly dry. This pricing environment offers expansion opportunities for certain of our systems as producers attempt to increase their wet gas and crude oil production. See Properties below for further asset descriptions.
- Well-positioned, well-maintained and efficient assets. We believe that our asset portfolio across 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.

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- Consistent track record of accretive acquisitions. Since our IPO in 2008, our management team has successfully executed eight related-party acquisitions and five third-party acquisitions, for an aggregate value of $2.9 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 Item 1A of this Form 10-K.

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.

During the year ended December 31, 2013, 57% of our gathering, transportation and treating throughput (excluding equity investment throughput and volumes measured in barrels) was attributable to natural gas production owned or controlled by Anadarko, and 56% of our processing throughput (excluding equity investment throughput and volumes 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 dedicated to us, pursuant to the terms of its applicable gathering agreements, all of the natural gas production it owns or controls from (i) wells that are currently connected to such gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to such gathering systems as those systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication 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 utilize the significant experience of Anadarko's management team.

As of December 31, 2013, WGP held 49,296,205 of our common units, representing a 41.2% limited partner interest in us, and, through its ownership of our general partner, indirectly held 2,394,345 general partner units, representing a 2.0% general partner interest in us, and 100% of our incentive distribution rights ("IDRs"). As of December 31, 2013, AMM, a subsidiary of Anadarko, separately held 449,129 common units, representing a 0.4% limited partner interest in us. As of December 31, 2013, the public held 67,577,478 common units, representing a 56.4% 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 them regarding certain reimbursement and indemnification matters. Although we believe our relationship with Anadarko provides us with a significant advantage in the midstream natural gas 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 acquire, construct or participate in the ownership of those assets. Anadarko is under no contractual obligation to offer any such 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 Item 1A and Item 13 of this Form 10-K for more information.

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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 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. In connection with our gathering services, we sometimes retain, stabilize and sell drip condensate, which falls out of the natural gas stream during gathering.
- 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 contaminants, such as water vapor, carbon dioxide and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the carbon dioxide and hydrogen sulfide from the gas stream.
- Processing. Processing removes the heavier and more valuable hydrocarbon components, which are extracted as NGLs. The residue remaining after extraction of NGLs meets the quality standards for long-haul pipeline transportation or commercial use.

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- 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 help temper seasonal demand and daily supply-demand shifts. We do not currently offer storage services or conduct marketing activities.

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.

There are two forms of contracts utilized 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, and the following map depicts our significant midstream assets as of December 31, 2013:

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Rocky Mountains—Northeast Wyoming

Bison treating facility. The Bison treating facility, located in northeastern Wyoming, consists of three amine treaters with a combined treating capacity of 450 MMcf/d (which varies depending upon the carbon dioxide content of the inlet gas). The assets also include three compressors with a combined compression of 5,230 horsepower and five generators with combined power output of 6.5 megawatts. We operate and have a 100% working interest in the Bison assets, which provide carbon dioxide treating services for coal-bed methane gas being gathered in the Powder River Basin to meet downstream pipeline specifications. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

Customers. Anadarko provided 70% of the throughput at the Bison treating facility for the year ended December 31, 2013. The remaining throughput was from one third-party producer.

Supply and delivery points. The Bison treating facility treats and compresses gas from the coal-bed methane wells in the Powder River Basin of Wyoming. The Bison pipeline, operated by TransCanada, is connected directly to the facility, which is currently the only inlet into the pipeline. The Bison treating facility also has access to the Fort Union and Thunder Creek pipelines.

Fort Union gathering system and treating facility. The Fort Union system is a gathering system operating within the Powder River Basin of Wyoming, starting in west central Campbell County and terminating at the Medicine Bow treating plant. The Fort Union gathering system consists of three parallel 106-mile, 24-inch pipelines and includes carbon dioxide treating facilities at the Medicine Bow plant. The system’s gas treating capacity will vary depending upon the carbon dioxide content of the inlet gas. At current carbon dioxide levels, the system is capable of treating and blending over 1.25 Bcf/d while satisfying the carbon dioxide specifications of downstream pipelines.

Customers. Anadarko is the field and construction operator of the Fort Union gathering system in which WES has a 14.81% interest. Anadarko and the other members of Fort Union, Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River LLC (37.04%), and Bargath, LLC (11.11%), 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.

Supply. Substantially all of Fort Union’s gas supply is comprised of coal-bed methane volumes that are either produced or gathered by the four Fort Union members throughout the Powder River Basin. As of December 31, 2013, the Fort Union system gathered gas from 2,300 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 1.2 million gross acres within the Powder River Basin as of December 31, 2013. 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 accesses the following interstate pipelines:

- Colorado Interstate Gas Company (“CIG”);
- Kinder Morgan Interstate Gas Transportation Company; and
- Wyoming Interstate Gas Company.

These pipelines serve gas markets in the Rocky Mountains and Midwest regions of the U.S.

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Hilight gathering system and processing plant. The 1,122-mile Hilight gathering system, located in northeastern Wyoming, provides low- and high-pressure gathering services for the area's conventional gas production and delivers natural gas to the Hilight plant for processing. The Hilight gathering system has 11 compressor stations with 31,741 combined horsepower. The Hilight plant has a capacity of 60 MMcf/d, utilizes a refrigeration process and provides for fractionation of the recovered NGL products into propane, butanes and natural gasoline.

Customers. Gas gathered and processed through the Hilight system is primarily from numerous third-party customers, with the six largest producers providing 73% of the system throughput during the year ended December 31, 2013.

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. Hilight is not connected to an active NGL pipeline; therefore all fractionated NGLs are sold locally through its truck and rail loading facilities.

MIGC transportation system. The MIGC system is a 241-mile interstate pipeline regulated by the Federal Energy Regulatory Commission ("FERC") and operating within the Powder River Basin of Wyoming. The MIGC system traverses the Powder River Basin from north to south, extending to Glenrock, Wyoming. As a result, the MIGC system is well positioned to provide transportation for the extensive natural gas volumes received from various coal-bed methane gathering systems and conventional gas processing plants throughout the Powder River Basin. MIGC offers both forward-haul and backhaul transportation services and is certificated for 175 MMcf/d of firm transportation capacity.

Customers. Anadarko is the largest firm shipper on the MIGC system, with 84% of throughput for the year ended December 31, 2013. The remaining throughput on the MIGC system was from 14 third-party shippers.
Revenues on the MIGC system are generated from contract demand charges and volumetric fees paid by shippers under firm and interruptible gas transportation agreements. Our current firm transportation agreement with Anadarko for 40 MMbtu/d extends through October 2018. In addition to its certificated forward-haul capacity, MIGC provides firm backhaul service subject to flowing capacity. We have 11 MMbtu/d contracted through May 2014 under backhaul service agreements that are renegotiated on an annual basis. Most of MIGC's interruptible gas transportation agreements are month-to-month with the remainder generally having terms of less than one year.
To maintain and increase throughput on our MIGC system, we must continue to contract capacity to shippers, including producers and marketers, for transportation of their natural gas. We monitor producer and marketing activities in the area served by our transportation system to identify new opportunities and to manage MIGC's throughput.

Supply. As of December 31, 2013, Anadarko had a working interest in over 1.2 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 seam producers and from 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 accesses the following interstate pipelines:

- CIG;
- Tallgrass Interstate Gas Transmission, LLC; and
- Wyoming Interstate Gas Company.

Volumes can also be delivered to the MGTC, Inc. (“MGTC”) intrastate pipeline, a Hinshaw pipeline that supplies local markets in Wyoming.

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Newcastle gathering system and processing plant. The 183-mile Newcastle gathering system, located in Weston and Niobrara Counties of Wyoming, was built to provide gathering services for conventional gas production in the area. The gathering system delivers into the Newcastle plant, which has gross capacity of 3 MMcf/d. The plant utilizes a refrigeration process and provides for fractionation of the recovered NGLs into propane and butane/gasoline mix products. We are a 50.0% joint-venture interest owner in the Newcastle facility, which is also owned by Black Hills Exploration and Production, Inc. (44.7%) and John Paulson (5.3%). The Newcastle gathering system includes a compressor station with 560 horsepower. The Newcastle plant has an additional 2,100 horsepower for refrigeration and residue compression.

Customers. Gas gathered and processed through the Newcastle system is from 11 third-party customers, with the largest three producers providing 84% of the system throughput during the year ended December 31, 2013. The largest producer provided 61% of the throughput during the year ended December 31, 2013.

Supply. The Newcastle gathering system and plant primarily service gas production from the Clareton and Finn-Shurley fields in Weston County. 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 MGTC pipeline for transport, distribution and sale.

Rocky Mountains—Southwest Wyoming

Granger gathering system and processing complex. The 857-mile Granger natural gas gathering system and gas processing facility is located in Sweetwater County, Wyoming. The Granger complex includes eight field compression stations and has 43,950 combined horsepower. The processing facility has cryogenic capacity of 200 MMcf/d, refrigeration capacity of 100 MMcf/d and NGL fractionation capabilities. The Granger complex also includes a plant with refrigeration capacity of 200 MMcf/d (“the Granger straddle plant”), which is accounted for as a capital lease and was acquired in connection with the acquisition of MGR. The current Granger straddle plant processing contract expires in December 2014.

Customers. Anadarko is the largest customer for the Granger complex with 32% of throughput for the year ended December 31, 2013. The remaining throughput was from various third-party customers, with the four largest shippers providing 57% 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 has 706 receipt points.

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

- CIG;
- The Kern River and Mountain Gas Transportation, Inc. (“MGTI”) pipelines via a connect with Rendezvous Pipeline Company;
- Northwest Pipeline Co. (“NWPL”);
- OTTCO; and
- QEP Resources (“QEP”).

The NGLs have market access to Enterprise’s Mid-America Pipeline Company (“MAPL”), which terminates at Mont Belvieu, Texas, as well as to local markets.

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Red Desert gathering system and processing complex. The Red Desert complex is a group of gathering and processing assets located in Sweetwater and Carbon Counties in Southwest Wyoming. As of December 31, 2013, the Red Desert complex included the Patrick Draw cryogenic processing plant with a capacity of 125 MMcf/d, the Red Desert cryogenic processing plant with a capacity of 48 MMcf/d, 1,039 miles of gathering lines, and related facilities.

Customers. For the year ended December 31, 2013, 3% 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 72% 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. Residue from the Red Desert complex is delivered to the CIG and Wyoming Interstate Company, Ltd. ("WIC") interstate pipelines, while NGLs are delivered to the MAPL, as well as to truck and rail loading facilities.

Rendezvous gathering system. The Rendezvous gathering system is a 338-mile mainline gathering system in southwestern Wyoming that delivers gas to our Granger complex and other locations. QEP is the operator of the Rendezvous gathering system and holds a 78% joint-venture interest, while we hold the remaining 22% joint-venture interest. The Rendezvous gathering system includes a compressor station with 7,485 horsepower.

Customers. QEP 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 QEP Field Services' Blacks Fork gas processing plant which connects to Questar Pipeline, NWPL and Kern River Pipeline via Rendezvous Pipeline Company, a FERC-regulated Questar affiliate.

OTTCO transportation system. The OTTCO system is a 242-mile intrastate pipeline in Sweetwater, Lincoln, and Uinta Counties in Wyoming, which provides natural gas gathering and transmission service and connects to our Red Desert and Granger complexes.

Customers. For the year ended December 31, 2013, 13% 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. Our current third-party firm transportation agreement for 21 MMbtu/d extends through December 2021.

Supply and delivery points. Supply points to the OTTCO transportation system include the Granger complex and the Exxon 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 also an interconnection with Kern River Pipeline.

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Rocky Mountains—Utah

Chipeta processing complex and NGL pipeline. We are the managing member and 75% owner of Chipeta. The remaining 25% membership interest is held by Ute Energy Midstream Holdings LLC (“Ute Energy”). Chipeta owns the Chipeta processing complex and the Natural Buttes refrigeration plant, which currently provide 970 MMcf/d of cryogenic and refrigeration processing capacity in the Greater Natural Buttes field in Uintah County, Utah. The Chipeta processing complex includes three processing trains (one refrigeration and two cryogenic). We also own 100% of a FERC-regulated NGL pipeline, comprised of two parallel NGL pipelines with a combined length of 32 miles, which connects the Chipeta and Natural Buttes plants to a third-party pipeline for NGL transportation out of the area.

Customers. Anadarko is the largest customer on the Chipeta system with 86% of the system throughput for the year ended December 31, 2013. The balance of throughput on the system during the year ended December 31, 2013 was from seven third-party customers.

Supply. The Chipeta system is well positioned to access Anadarko and third-party production in the Uintah Basin. Anadarko controls 223,000 gross acres in the Uintah Basin. Chipeta is connected to both Anadarko’s Natural Buttes gathering system and to the Three Rivers gathering system owned by Ute Energy and a third party.

Delivery points. The Chipeta plant delivers NGLs to the MAPL, which provides transportation through the Seminole and Texas Express pipelines in West Texas and ultimately to the NGL markets at Mont Belvieu, Texas and the Texas Gulf Coast. The Chipeta plant has natural gas delivery points through the following pipelines:

- CIG;
- Questar Pipeline Company; and
- WIC.

Clawson gathering system and treating facility. The 47-mile Clawson gathering system, located in Carbon and Emery Counties of Utah, was built in 2001 and provides gathering, dehydration, compression and treating services for Anadarko’s coal-bed methane development of the Ferron Coal play. The Clawson gathering system includes a compressor station with 6,310 horsepower and a carbon dioxide treating facility.

Customers. Anadarko is the largest shipper on the Clawson gathering system with 97% of the total throughput delivered into the system during the year ended December 31, 2013. The remaining throughput on the system was from one third-party producer.

Supply. The Clawson Springs field covers 7,000 acres and produces primarily from the Ferron Coal play.

Delivery points. The Clawson gathering system delivers into Questar Transportation Services Company’s pipeline.

Helper gathering system and treating facility. The 67-mile Helper gathering system, located in Carbon County, Utah, provides gathering, dehydration, compression and treating services for Anadarko's coal-bed methane development of the Ferron coal play. The Helper gathering system includes two compressor stations with 14,075 combined horsepower and two carbon dioxide treating facilities.

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 Uintah Basin that produce from the Ferron Coal play. The Helper field covers 18,900 acres, and the Cardinal Draw field, which lies immediately to the east of Helper field, covers 17,300 acres.

Delivery points. The Helper gathering system delivers into Questar Transportation Services Company's pipeline. Questar 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 U.S., primarily California.

Rocky Mountains—Colorado

DJ Basin gathering system and processing plants. The Platte Valley and Wattenberg systems are located in the Denver-Julesburg Basin ("DJ Basin"), northeast of Denver, Colorado. The Platte Valley system consists of a processing plant with current cryogenic capacity of 100 MMcf/d, two fractionation trains, a 1,105-mile natural gas gathering system and related equipment. The Platte Valley gathering system has 13 compressor stations with 17,011 combined horsepower.
The Wattenberg gathering system is a 2,020-mile wet gas gathering system and includes seven compressor stations with 103,524 combined horsepower. The Fort Lupton processing plant, part of the Wattenberg system, has two trains with combined processing capacity of 105 MMcf/d. The Platteville treating facility, also part of the Wattenberg system, has an amine treater with a treating capacity of 34 MMcf/d. See also Assets Under Construction below.

Customers. For the year ended December 31, 2013, 7% of the Platte Valley system throughput was from Anadarko and the remaining throughput was from various third-party customers, with the largest providing 83% of the throughput. Anadarko-operated production represented 68% of Wattenberg system throughput during the year ended December 31, 2013. 28% of Wattenberg system throughput was from two third-party producers and the remaining throughput was from various third-party customers.

Supply and delivery points for the Platte Valley gathering system and processing plant. There were 575 receipt points connected to the Platte Valley gathering system as of December 31, 2013. The Platte Valley system is connected to our Wattenberg gathering system and is primarily supplied by the Wattenberg field and covers portions of Adams, Arapahoe, Boulder, Broomfield, Denver, Elbert, and Weld Counties, Colorado. The Platte Valley system delivers NGLs to local markets and is connected to the Overland Pass Pipeline and the Wattenberg Pipeline (formerly the Buckeye Pipeline). In addition, the Platte Valley system can deliver to the CIG and Xcel Energy residue pipelines.

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Supply and delivery points for the Wattenberg gathering system and Fort Lupton processing plant. There were 2,331 receipt points and over 6,500 wells connected to the gathering system as of December 31, 2013. The Wattenberg gathering system is primarily supplied by the Wattenberg field and covers portions of Adams, Arapahoe, Boulder, Broomfield and Weld Counties. Anadarko controls 762,000 gross acres in the Wattenberg field. Anadarko drilled 388 wells and completed 7,702 fracs in connection with its active recompletion and re-frac program at the Wattenberg field during the year ended December 31, 2013, and has identified 4,000 opportunities to increase production including new well locations, re-fracs and recompletions.

As of December 31, 2013, the Wattenberg gathering system has five delivery points, including the following primary delivery points:

- Anadarko's Wattenberg processing plant;
- our Fort Lupton processing plant; and
- our Platte Valley processing plant.

The two remaining delivery points are DCP Midstream's Spindle processing plant and AKA Energy's Gilcrest processing plant. All delivery points are connected to the CIG and Xcel Energy residue pipelines and the Overland Pass Pipeline for NGLs. In addition, a truck-loading facility provides access to local NGL markets. Anadarko's Wattenberg and our Platte Valley processing plants also have NGL connections to the Wattenberg Pipeline (formerly the Buckeye Pipeline). The Front Range Pipeline, which was under construction at December 31, 2013, is being built to transport NGLs from the DJ Basin to Skellytown, Texas. See also Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

White Cliffs pipeline. The White Cliffs pipeline is a 527-mile, 12-inch crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. It has a current capacity of 70 MBbls/d and is undergoing an expansion project for an additional 80 MBbls/d, projected to be completed in the first half of 2014. At the point of origin, it has a 100,000-barrel storage facility adjacent to a truck-unloading facility. We own a 10% joint-venture interest in White Cliffs, which is also owned by SemGroup Pipeline LLC (51%), Plains All American Pipeline, LP (34%) and Noble Energy, Inc. (5%).

Customers. The White Cliffs pipeline had two committed shippers, including Anadarko, during the year ended December 31, 2013. In addition, other parties may ship on the White Cliffs pipeline at FERC-based rates.

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.

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Mid-Continent

Hugoton gathering system. The 2,053-mile Hugoton gathering system provides gathering service to the Hugoton field and is primarily located in Seward, Stevens, Grant and Morton Counties of Southwest Kansas and Texas County in Oklahoma. The Hugoton gathering system has 44 compressor stations with 92,097 combined horsepower.

Customers. Anadarko is the largest customer on the Hugoton gathering system with 84% of the system throughput during the year ended December 31, 2013. In addition, 7% of the throughput on the Hugoton system was from two third-party shippers, with the balance from various other third-party shippers.

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 jointly by Pioneer Natural Resources Corporation (51%) and Anadarko (49%). The Satanta plant processes NGLs and helium, and delivers residue into the Kansas Gas Services and Southern Star pipelines. The system is also connected to DCP Midstream's National Helium Plant, which extracts NGLs and delivers residue into the Panhandle Eastern Pipe Line.

North-central Pennsylvania

Marcellus gathering systems. The gathering systems in the Non-Operated Marcellus Interest and the Anadarko-Operated Marcellus Interest serve production from the Marcellus shale in north-central Pennsylvania. The Non-Operated Marcellus Interest includes the Liberty and Rome gas gathering systems, with interflow gas from the Smithfield, Auburn, Litchfield and Overfield gas gathering systems. The Liberty and Rome systems consist of 431 miles of pipelines within Lycoming, Sullivan, Bradford, Wyoming and Susquehanna Counties in Pennsylvania. A subsidiary of Access Midstream Partners is the field and construction operator of the Non-Operated Marcellus Interest gathering systems, in which we and Access Midstream Partners each have a 33.75% interest.

The Anadarko-Operated Marcellus Interest includes the Larry's Creek, Seely and Warrensville gas gathering systems, which consist of 99 miles of pipelines within Lycoming County in Pennsylvania. Anadarko is the field and construction operator of the Anadarko-Operated Marcellus Interest gathering systems, in which we and Anadarko each have a 33.75% interest.

The other owners of the gathering systems in the Non-Operated Marcellus Interest and the Anadarko-Operated Marcellus Interest are Mitsui E&P USA, LLC (16.25%) and Statoil Pipelines (16.25%).

Customers. As of December 31, 2013, 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, 2013, Anadarko represented 23% and 36% of throughput on the Non-Operated Marcellus Interest 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, 2013, Anadarko had a working interest in over 413,000 gross acres within the Marcellus shale. The Non-Operated Marcellus Interest gathering systems have access to the Transcontinental Gas Pipeline Company, LLC ("TRANSCO") pipeline, the Tennessee Gas Pipeline Company, LLC and the Millennium Pipeline Company, L.L.C. The Anadarko-Operated Marcellus Interest gathering systems have access to the TRANSCO pipeline.

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East Texas

Dew gathering system. The 324-mile Dew gathering system is located in Anderson, Freestone, Leon and Robertson Counties of East Texas. The system provides gathering, dehydration and compression services and ultimately delivers into the Pinnacle gas treating system for any required treating. The Dew gathering system has nine compressor stations with 36,265 combined horsepower.

Customers. Anadarko is the only shipper on the Dew gathering system.

Supply. As of December 31, 2013, Anadarko had 778 producing wells in the Bossier play and controlled 109,000 gross acres in the area.

Delivery points. The Dew gathering system has delivery points with Kinder Morgan’s Tejas pipeline and with Pinnacle, which is the primary delivery point and is described in more detail below.

Pinnacle gathering system and treating facility. The Pinnacle system includes the 270-mile Pinnacle gathering system and the Bethel treating facility. The Pinnacle system provides sour gas gathering and treating service in Anderson, Freestone, Leon, Limestone and Robertson Counties of East Texas. The Bethel treating facility, located in Anderson County, has total carbon dioxide treating capacity of 502 MMcf/d and 20 LTD of sulfur treating capacity.

Customers. Anadarko is the largest shipper on the Pinnacle gathering system with 91% of system throughput for the year ended December 31, 2013. The remaining throughput on the system during that period was from four 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, which includes the Cotton Valley Lime formations, which contain relatively high concentrations of sulfur and carbon dioxide.

Delivery points. The Pinnacle gathering system is connected to the following pipelines:

- Atmos Texas pipeline;
- Enbridge Pipelines (East Texas) LP pipeline;
- Energy Transfer Fuels pipeline;
- Enterprise Texas Pipeline, LP pipeline;
- ETC Texas Pipeline, Ltd pipeline; and
- Kinder Morgan Tejas pipeline.

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

Mont Belvieu JV fractionation trains. The Mont Belvieu JV owns two NGL fractionation trains located in Mont Belvieu, Texas. Each train has the capability to fractionate up to 85 MBbls/d of NGLs. Enterprise Products Partners L.P. (“Enterprise”) is the operator of the Mont Belvieu JV, with a 75% joint-venture interest, while we hold the remaining 25% joint-venture interest.

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 Enterprise-operated Seminole Pipeline, the Skelly-Belvieu pipeline, and the Texas Express Pipeline. Individual NGLs are delivered to end users either through customer-owned pipelines that are connected to nearby petrochemical plants or via export terminal. See also Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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South and West Texas

Haley gathering system. The 120-mile Haley gathering system provides gathering and dehydration services in Loving County, Texas and gathers a portion of Anadarko's production from the Delaware Basin.

Customers. Anadarko's production represented 66% of the Haley gathering system's throughput for the year ended December 31, 2013. The remaining throughput was attributable to two third-party producers.

Supply. In the greater Delaware Basin, Anadarko had access to 416,000 gross acres as of December 31, 2013, 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 the El Paso Natural Gas pipeline or the Enterprise GC, LP pipeline for ultimate delivery into Energy Transfer's 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.

Brasada processing facility, pipelines and stabilization facility. The Brasada facility, located near the town of Cotulla in La Salle County, Texas, began operations in June 2013 for the processing of gas and the stabilization of condensate from Anadarko's production in the Eagleford shale. The Brasada facility consists of a 200 MMcf/d cryogenic processing plant, a 15 MBbls/d condensate stabilization facility, a 30-mile 24-inch gas pipeline, a 30-mile 8-inch condensate pipeline, and other gas treating facilities.

Customers. Anadarko provides 100% of the throughput to the Brasada facility. 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 413,000 gross acres.

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

Assets Under Construction

We currently have the following significant project scheduled for completion in 2014 that is supported by long-term, fee-based throughput commitments from Anadarko.

• Lancaster plant in the DJ Basin: We are currently constructing a new cryogenic plant which will process production from the Niobrara and Codell formations in the Wattenberg field. The first train of the new plant has a capacity of 300 MMcf/d and is expected to begin service in the first quarter of 2014. Anadarko has agreed to a fee-based contract with a 10-year throughput guarantee of 270 MMcf/d, which will begin on the plant's in-service date. A second train has been approved that will provide an additional 300 MMcf/d of capacity and is expected to be completed in 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.

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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.

Gathering Systems and Processing Plants

The following table summarizes the primary competitors for our gathering systems and processing plants at December 31, 2013.

System	Competitor(s)
Anadarko-Operated Marcellus Interest gathering systems	PVR Midstream and National Fuel Gas Midstream
Bison treating facility	Thunder Creek Gas Services and Fort Union (treating only)
Brasada processing facility, pipeline and stabilization facility	Enterprise, Energy Transfer, and Kinder Morgan, Inc.
Chipeta processing complex	QEP and Kinder Morgan, Inc.
Dew and Pinnacle gathering systems and Pinnacle treating facility	ETC Texas Pipeline, Ltd., Enbridge Pipelines (East Texas) LP, XTO Energy and Kinder Morgan Tejas Pipeline, LP
Fort Union gathering system and treating facility	Bison treating facility (carbon dioxide treating services only), MIGC, Thunder Creek Gas Services, and TransCanada
Granger gathering system and processing complex	Williams Field Services, Enterprise/TEPPCO and QEP
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 Midstream, ONEOK Gas Gathering Company, Thunder Creek Gas Services, Crestwood-Access, Tallgrass Energy Partners, and Rowdy Gathering Company
Hugoton gathering system	ONEOK Gas Gathering Company, DCP Midstream Partners, LP, Pioneer Natural Resources 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 Midstream
Non-Operated Marcellus Interest gathering systems	PVR Midstream
Platte Valley gathering system and processing plant	DCP Midstream and AKA Energy
Red Desert gathering system and processing complex	Williams Field Services and QEP

Rendezvous gathering system	Enterprise/TEPPCO
Wattenberg gathering system and processing plant	DCP Midstream and AKA Energy

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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, TransCanada'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.

REGULATION OF OPERATIONS

Safety and Maintenance

Some 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 ("PSI Act") and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("PIPES Act"). The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas and NGL pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, 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 established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission 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. 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.

Most recently these pipeline safety laws were amended on January 3, 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 transportation pipelines. Among other things, the 2011 Pipeline Safety Act directed the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission 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 also 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 or any issuance or reinterpretation of PHMSA guidance with respect thereto could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and 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 2014. 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 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. PHMSA continues to evaluate the public comments received with respect to more stringent integrity management programs and recently, pursuant to one of the requirements in the 2011 Pipeline Safety Act, published a proposed rulemaking on August 1, 2013, seeking comments on whether an expansion of integrity management requirements beyond current high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along the pipeline.

In addition, we are 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. In addition, 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 Process Safety Management (“PSM”) regulations, as well as the EPA’s Risk Management Program (“RMP”), 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 those PSM and RMP requirements at regulated facilities, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in the recent 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 recent actions by PHMSA are currently subject to judicial and administrative challenge 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.

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Interstate Transportation 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 is 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 MIGC may offer to its customers;
- certification and construction of new facilities;
- acquisition, extension, disposition or abandonment of facilities;
- maintenance of accounts and records;
- internet posting requirements for available capacity, discounts and other matters;
- pipeline segmentation to allow multiple simultaneous shipments under the same contract;
- capacity release to create a secondary market for MIGC’s 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.
On October 16, 2008, FERC issued Order No. 717, which promulgated new standards of conduct for transmission providers to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. Order No. 717 implements revised standards of conduct that include three primary rules: (1) the “independent functioning rule,” which requires transmission function and marketing function employees to operate independently of each other; (2) the “no-conduit rule,” which prohibits passing transmission function information to marketing function employees; and (3) the “transparency rule,” which imposes posting requirements to help detect any instances of undue preference. FERC also clarified in Order No. 717 that existing waivers to the standards of conduct (such as those held by MIGC) shall continue in full force and effect. FERC has issued a number of orders clarifying certain provisions of the Standards of Conduct under Order No. 717, however the subsequent orders did not substantively alter the Standards of Conduct.

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In May 2005, FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass-through partnership entity, if the pipeline proves that the ultimate owner of its equity interests has an actual or potential income tax liability on public utility income. The policy statement also provides that whether a pipeline's owners have such actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. In August 2005, FERC dismissed requests for rehearing of its policy statement. The tax allowance policy and a related order were appealed to the D.C. Circuit. The D.C. Circuit issued an order on May 29, 2007 in which it denied these appeals and upheld FERC's tax allowance policy and the application of that policy on all points subject to appeal. The D.C. Circuit denied rehearing of the May 29, 2007 decision on August 20, 2007, and the D.C. Circuit's decision is final. Whether a pipeline's owners have actual or potential income tax liability will be reviewed by FERC on a case-by-case basis. How the policy statement affirmed by the D.C. Circuit is applied in practice to pipelines owned by publicly traded partnerships could impose limits on a pipeline's ability to include a full income tax allowance in its cost of service.

On April 17, 2008, FERC issued a proposed policy statement regarding the composition of proxy groups for determining the appropriate return on equity for natural gas and oil pipelines using FERC's Discounted Cash Flow ("DCF") model. In the policy statement, which modified a proposed policy statement issued in July 2007, FERC concluded (1) master limited partnerships ("MLPs") should be included in the proxy group used to determine return on equity for both oil and natural gas pipelines; (2) there should be no cap on the level of distributions included in FERC's current DCF methodology; (3) Institutional Brokers' Estimate System forecasts should remain the basis for the short-term growth forecast used in the DCF calculation; (4) the long-term growth component of the DCF model should be limited to fifty percent of long-term gross domestic product; and (5) there should be no modification to the current two-thirds and one-third weighting of the short-term and long-term growth components, respectively. FERC also concluded that the policy statement should govern all gas and oil rate proceedings involving the establishment of return on equity that are pending before FERC. FERC's policy determinations applicable to master limited partnerships are subject to further modification, and it is possible that these policy determinations may have a negative impact on MIGC's rates in the future.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005 (the "EPAct 2005"). Among other matters, the EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior in contravention of rules and regulations prescribed by FERC and, furthermore, provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of the EPAct 2005, and subsequently denied rehearing. The rules 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 new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, as well as otherwise 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. The EPAct 2005 also amends the NGA and the Natural Gas Policy Act of 1978 ("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. In connection with this enhanced civil penalty authority, FERC issued a policy statement on enforcement to provide guidance regarding the enforcement of the statutes, orders, rules and regulations it administers, including factors to be considered in determining the appropriate enforcement action to be taken. 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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In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Order No. 704 requires buyers and sellers of natural gas above a de minimis level, including entities not otherwise subject to FERC jurisdiction, to submit on May 1 of each year an annual report to FERC describing their aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. In addition, on November 15, 2012, FERC issued a Notice of Inquiry seeking comments on whether natural gas market transparency will be improved by requiring all market participants engaged in sales of wholesale physical natural gas in interstate commerce to report quarterly to the Commission every natural gas transaction within the Commission's NGA jurisdiction that entails physical delivery for the next day or for the next month.

Order No. 720, issued on November 20, 2008, increases the Internet posting obligations of interstate pipelines, and also requires "major non-interstate" pipelines (defined as pipelines with annual deliveries of more than 50 million MMBtu) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu per day or greater. In October 2011, Order No. 720, as clarified by orders on clarification and rehearing, was vacated by the Court of Appeals for the Fifth Circuit with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order No. 720, as clarified, remained applicable to interstate pipelines with respect to the additional posting requirements.

On May 20, 2010, FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. Order No. 735 also extends FERC's periodic review of the rates charged by the subject pipelines from three years to five years. FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 became effective on April 1, 2011. On December 16, 2010, FERC issued Order No. 735-A, which generally reaffirmed Order No. 735, with certain modifications. FERC has issued a Notice of Proposed Rulemaking to consider issues related to existing semiannual storage reporting requirements for both interstate pipelines and section 311 and Hinshaw pipelines.

In 2008, FERC also took action to ease restrictions on the capacity release market, in which shippers on interstate pipelines can transfer to one another their rights to pipeline and/or storage capacity. Among other things, Order No. 712, as modified on rehearing, removes the price ceiling on short-term capacity releases of one year or less, allows a shipper releasing gas storage capacity to tie the release to the purchase of the gas inventory and the obligation to deliver the same volume at the expiration of the release, and facilitates Asset Management Agreements ("AMAs") by exempting releases under qualified AMAs from: the competitive bidding requirements for released capacity; FERC's prohibition against tying releases to extraneous conditions; and the prohibition on capacity brokering.

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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. 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.

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.

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 transportation is also 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 natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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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 in the Chipeta processing complex provide service pursuant to GNB NGL Pipeline LLC's FERC tariff as a common carrier under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. FERC regulation requires that interstate liquid pipeline rates, including rates for transportation of NGLs, be filed with FERC and that these rates be "just and reasonable" and not unduly discriminatory. Rates of interstate NGL pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 2.65%. This adjustment is subject to review every five years. Under FERC's regulations, an NGL pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology.
The Interstate Commerce Act permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. The just and reasonable rate used to calculate refunds cannot be lower than the last tariff rate approved as just and reasonable. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for charges in excess of a just and reasonable rate for a period of up to two years prior to the filing of a complaint.

Pipeline Safety Legislation

On January 3, 2012, the President signed into law the 2011 Pipeline Safety Act. This legislation provides a four-year reauthorization of the federal pipeline safety programs administered by the PHMSA pursuant to the NGPSA and HLPSA. The 2011 Pipeline Safety Act increases the maximum amount of civil penalties the United States can seek from pipeline owners or operators who violate pipeline safety rules and regulations. It authorizes the PHMSA (i) to extend existing integrity management requirements to additional pipelines beyond high-consequence areas, subject to Congressional review, and (ii) to require installation of automatic and remote-controlled shut-off valves on newly constructed transmission pipelines and for ones that are entirely replaced. The act also imposes new notification and reporting requirements. Many specific requirements are expected to be developed as part of future regulations. While we cannot predict how PHMSA will implement the act and other regulatory initiatives relating to pipeline safety, these provisions could have a material effect on our operations and could subject us to more comprehensive and stringent safety requirements and greater penalties for violations of safety rules.

Financial Reform Legislation

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

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ENVIRONMENTAL MATTERS

General

Our operations are subject to stringent federal, regional, 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 various permits to conduct regulated activities;
- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- requiring investigatory and remedial actions to mitigate or eliminate pollution conditions caused by our operations or attributable to former operations; and
- imposing substantial liabilities for pollution resulting from our midstream activities.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of investigatory and remedial obligations and the issuance of orders enjoining future operations or imposing additional compliance requirements. Also, certain environmental statutes impose strict, and in some cases, joint and several liability for costs required to clean up and restore sites where hydrocarbons or wastes have been disposed or otherwise released. Consequently, we may be subject to environmental liability at our currently owned or operated facilities for conditions caused by others prior to our involvement.

In addition, our operations and construction activities are subject to state and local ordinances that restrict the time, place or manner in which those activities may be conducted so as to reduce or mitigate nuisance-type conditions, such as excessive levels of dust or noise or increased traffic congestion, requiring us to take curative actions to reduce or mitigate such conditions. However, the performance of such actions has not had a material adverse effect on our results of operations.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in substantial compliance with applicable environmental laws and regulations and we do not believe that our compliance with such legal requirements will have a material adverse effect on our business, financial condition, results of operations or cash flows. Nonetheless, the trend in environmental regulation is to place more restrictions and limitations 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. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. While we believe that we are in substantial compliance with existing environmental laws and regulations, there is no assurance that the current conditions will continue in the future. Below is a discussion of several of the material environmental laws and regulations that relate to our business.

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Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA" or the "Superfund law"), 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 found 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. We generate materials in the course of our ordinary operations that are regulated as "hazardous substances" under CERCLA or similar state laws and, as a result, may be jointly and severally liable under CERCLA, or similar state laws, for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate non-hazardous and hazardous wastes that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended (the "RCRA"), and comparable state statutes. While the RCRA regulates both non-hazardous and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the ordinary course of our operations, we generate wastes constituting non-hazardous waste and, in some instances, hazardous wastes. While certain petroleum production wastes are excluded from the RCRA's hazardous waste regulations, it is possible that these wastes will in the future be designated as "hazardous wastes" and be subject to more rigorous and costly disposal requirements, which could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We own or lease properties where petroleum hydrocarbons are being or have been handled for many years. We have generally utilized 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, the RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws and regulations 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, on August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas and natural gas liquid production, processing, storage and transportation activities, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with production and processing activities.

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These final rules, among other things, revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requiring monitoring of connectors, pumps, pressure relief devices and open-ended lines. In addition, these rules establish requirements regarding emissions at gathering systems, boosting facilities, and onshore natural gas processing plants from: (i) wet seal and reciprocating compressors; (ii) specified pneumatic controllers; and (iii) specified storage vessels. Compliance with these requirements may require modifications to certain of our operations, including the installation of new equipment to control emissions from our compressors that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Climate Change

In 2009, the EPA adopted rules establishing a reporting program for emissions of carbon dioxide, methane and other greenhouse gases, or “GHGs,” from specified large GHG emissions sources in the United States and subsequently expanded the scope of these rules to include the reporting of GHG emissions from onshore oil and natural gas processing, transmission, storage and distribution facilities. Operators of covered sources in the United States must annually monitor and report these GHG emissions to the EPA and certain state agencies. Certain of our facilities are subject to the federal GHG reporting requirements because of combustion GHG emissions and potential fugitive emissions that exceed reporting thresholds. While our compliance with this reporting program has increased our operating costs, we presently do not believe that these increased costs have a material adverse effect on our results of operations.
In addition, following its determination in December 2009 that emissions of GHGs present a danger to public health and the environment, the EPA promulgated regulations in 2010 establishing Title V and Prevention of Significant Deterioration (“PSD”) permitting requirements for large sources of GHGs. The sources subject to these permitting requirements may be required to install best available control technology (“BACT”) to limit emissions of GHGs should they otherwise emit large volumes of GHGs. Best available control technology is determined on a case-by-case basis by the relevant permitting agency to date, whether that be the EPA or a state agency. However, BACT has generally required efficient combustion requirements rather than post-combustion GHG capture requirements, in which event we do not anticipate that such requirements would have a material adverse effect on the cost of our operations. Moreover, while Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions. Most of these cap-and-trade programs work by requiring major sources of emissions to acquire and surrender emission allowances, with the number of allowances available for purchase being reduced each year in an effort to achieve the overall GHG emission reduction goal. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our services, results of operations, and cash flows. Finally, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform will include a carbon tax, which could impose additional direct costs on our operations and reduce demand for our services. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets and operations.

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Water Discharges

The federal Water Pollution Control Act, as amended (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 U.S. and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA, the Army Corps of Engineers or an analogous state agency. Spill prevention, control and countermeasure requirements of 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. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws.
The federal Oil Pollution Act of 1990, as amended ("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. 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 OPA includes owners and operators of onshore facilities, such as our plants and pipelines. Under OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible. We believe that we are in substantial compliance with applicable provisions of the Clean Water Act, OPA and analogous state laws.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions but the EPA has asserted limited regulatory authority over certain hydraulic fracturing activities and has indicated it may seek to further expand its regulation of hydraulic fracturing. Also, the Bureau of Land Management has proposed regulations applicable to hydraulic fracturing conducted on oil and gas leases on Indian lands. In addition, legislation has been introduced from time to time before Congress to provide for federal regulation of hydraulic fracturing.
Moreover, some states in which we operate, including Colorado, Kansas, Oklahoma, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. For example, in November 2013, voters approved local ballot initiatives in the Colorado cities of Boulder, Broomfield, Fort Collins and Lafayette to restrict oil and gas development, including the use of hydraulic fracturing, either temporarily or permanently, within their respective cities' limits. Further, several federal governmental agencies have conducted or are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality, the EPA and the U.S. Department of Energy. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While we do not conduct hydraulic fracturing, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process were to be adopted in areas where our oil and natural gas exploration and production customers, including Anadarko, operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of production activities, which could reduce demand for our gathering and processing services.

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Endangered Species Considerations

The Endangered Species Act, as amended (the “ESA”), restricts activities that may affect endangered or threatened species or their habitats. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. 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 on September 9, 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.

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, 2013, Anadarko employed 382 people who provided direct, full-time support to our operations. All of the employees required to conduct and support our operations are employed by Anadarko and all of our direct, full-time personnel are subject to a services and secondment agreement between our general partner and Anadarko. None of these employees are covered by collective bargaining agreements, and Anadarko considers its employee relations to be good.

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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 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," "shoul 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;
- operating results;
- competitive conditions;
- technology;
- 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;
- supply of, demand for, and the price of, oil, natural gas, NGLs and related products or services;
- weather;
- inflation;
- availability of goods and services;
- general economic conditions, either internationally or domestically or in the jurisdictions in which we are doing business;
- changes in regulations at the federal, state and local level or the inability to timely obtain or maintain permits that could affect our and our customers' activities; environmental risks; regulations by FERC and liability under federal and state laws and regulations;
- legislative or regulatory changes affecting our status as a partnership for federal income tax purposes;
- changes in the financial or operational condition of Anadarko;
- changes in Anadarko's capital program, strategy or desired areas of focus;
- our commitments to capital projects;
- ability to use our RCF;
- creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners and other parties;
- our ability to repay debt;
- our ability to mitigate 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;

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- 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;
- 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.

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, 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, 2013, 57% of our gathering, transportation and treating throughput (excluding equity investment throughput and volumes measured in barrels) was comprised of natural gas production owned or controlled by Anadarko. For the year ended December 31, 2013, 56% of our total processing throughput (excluding equity investment throughput and volumes 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.

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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, including the Tronox Adversary Proceeding, as defined and described in Note 17—Contingencies—Tronox Litigation in the Notes to the Consolidated Financial Statements under Item 8 of Anadarko's Form 10-K for the year ended December 31, 2013 (which is not, and shall not be deemed to be, incorporated by reference herein).

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, we 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, 2013 (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.

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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 2013 distribution of $0.60 per unit per quarter, or $2.40 per unit per year, we will require available cash of $92.6 million per quarter, or $370.4 million per year, based on the number of general partner units and common units outstanding at January 31, 2014. 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:

- the level of capital expenditures we make;
- the level of our 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.

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

Lower natural gas, NGL or oil prices could impact natural gas and oil exploration and production activity levels and result in a decline in the production of natural gas and condensate, resulting in reduced throughput on our systems. Any such decline could also potentially affect our vendors', suppliers' and customers' ability to continue operations. In addition, such a decline would reduce the amount of NGLs and condensate we retain and sell. As a result, lower natural gas prices could have an adverse effect on our business, results of operations, financial condition and our ability to make 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, in recent years, market prices for natural gas have declined substantially from the highs achieved in 2008, and the increased supply resulting from the rapid development of shale plays throughout North America has contributed significantly to this trend. Factors impacting commodity prices include the following:

- domestic and worldwide economic 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 anticipated future prices of natural gas, NGLs and other commodities.

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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, 2013, 26% 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 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 by those activities. 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, and on various dates thereafter, a portion of the commodity price swap agreements that we have entered into with Anadarko 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.

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.

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 midstream services.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted limited regulatory authority over certain hydraulic fracturing activities, and has indicated it may seek to further expand its regulation of hydraulic fracturing conducted on oil and gas leases on federal and Indian lands. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing.

Certain states in which we operate, including Colorado, Kansas, Oklahoma, Texas and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations. Further, 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. For example, in November 2013, voters approved local ballot initiatives in the Colorado cities of Boulder, Broomfield, Fort Collins and Lafayette to restrict oil and gas development, including the use of hydraulic fracturing, either temporarily or permanently, within their respective cities' limits. Further, several federal governmental agencies have conducted or are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality, the EPA and the U.S. Department of Energy. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, local or municipal legal restrictions are adopted in areas where our oil and gas exploration and production customers, including Anadarko, operate, those operators may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of natural gas wells, which events could decrease the need for our midstream services and could adversely affect our financial position, results of operations, cash flows, and ability to make distributions to our unitholders. Increased regulation of the hydraulic fracturing process could also lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques.

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

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

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. While our sector has rebounded from lows seen in 2008, the repricing of credit risk and the current relatively weak economic conditions have made, and will likely continue to make, it difficult for some entities to obtain funding. In addition, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to the borrower's current debt, and reduced, or in some cases, ceased to provide funding to borrowers. Further, we may be unable to obtain adequate funding under our RCF if our lending counterparties become unwilling or unable to meet their funding obligations. Due to these factors, we cannot be certain that funding will be available if needed and to the extent required on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to execute our business plans, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders.

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Restrictions in the indentures governing our 5.375% Senior Notes due 2021 (the “2021 Notes”), 4.000% Senior Notes due 2022 (the “2022 Notes”) and 2.600% Senior Notes due 2018 (the “2018 Notes” and together with the 2021 Notes, and the 2022 Notes, “the Notes”) or the RCF may limit our ability to capitalize on acquisition 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.

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

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

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

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

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

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

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.

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.

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

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions for periods in which we record losses for financial accounting purposes and may not make cash distributions for periods in which we record net earnings for financial accounting purposes.
The amount of available cash we need to pay the distribution announced for the quarter ended December 31, 2013, on all of our units and the corresponding distribution on our general partner’s 2.0% interest for four quarters is $370.4 million.

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 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, 2013, we had $105.3 million of goodwill on our balance sheet. Similar to the carrying value of the assets we acquired from Anadarko, 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.

MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the NGA and the EPAct 2005. Under the NGA, FERC has the authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as:

- rates, services and terms and conditions of service;
- the certification and construction of new facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- the maintenance of accounts and records;
- relationships between affiliated companies involved in certain aspects of the natural gas business; and
- market manipulation in connection with interstate sales, purchases or transportation of natural gas.

In addition, 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.
GNB NGL Pipeline, LLC, our common carrier liquids pipeline, is 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 MIGC and GNB NGL Pipeline, LLC could be adversely affected.

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

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

Climate change legislation or regulatory initiatives could increase our operating and capital costs and could have the indirect effect of decreasing throughput available to our systems or demand for the products we gather, process and transport.

Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are greenhouse gases (“GHGs”). In December 2009, the EPA issued an Endangerment Finding which determined that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on its finding, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that establish Title V and PSD permitting requirements for large sources of GHGs. Sources subject to these permitting requirements may be required to install BACT to limit emissions of GHGs, which is determined on a case-by-case basis by the state or EPA permitting agency and has generally required efficient combustion requirements. 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 reporting of GHG emissions from specified large GHG emissions sources in the United States, including onshore oil and natural gas processing, transmission, storage and distribution facilities, on an annual basis. In addition, Congress has from time to time considered legislation to reduce emissions of GHGs, and numerous states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. 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. Finally, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform will include a carbon tax, which could impose additional direct costs on our operations and reduce demand for our services.

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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 Commodities Futures Trading Commission (the “CFTC”), the SEC and other federal regulators to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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 and for options and swaps that are their economic equivalent. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations so the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. 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 requirements for swaps entered 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. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. Rules that require end-users to post initial or variation margin could impact liquidity and reduce cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules for uncleared swaps are not yet final and their impact on us is not yet clear.

The financial reform legislation may also require some counterparties to spin off some of their derivatives activities to separate entities, which may not be as creditworthy. In addition, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices. To the extent they are unhedged, our revenues could be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity price contracts, and increase our exposure to less creditworthy counterparties. 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.

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.

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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 established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission 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:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. 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 continued safe and reliable operations of our gathering and transmission lines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly 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. PHMSA continues to evaluate the public comments received with respect to more stringent integrity management programs and, pursuant to one of the requirements in the 2011 Pipeline Safety Act, published a proposed rulemaking on August 1, 2013, seeking comments on whether an expansion of high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along a pipeline.

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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 transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines is above 30% of specified minimum yield strength, and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission 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 also 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 or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial position. For example, PHMSA and one or more state regulators, including the Texas Railroad Commission, have in the recent 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 recent 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 OSHA PSM and EPA 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.

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, regional, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include the following:

- the federal Clean Air Act and analogous state laws that impose obligations related to emissions of air pollutants;
- the federal Comprehensive Environmental Response, Compensation and Liability Act and analogous state laws that require and regulate the cleanup of hazardous substances that have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal Resources Conservation and Recovery Act and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities; and
- the federal Toxic Substances Control Act and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These 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 sanctions, including 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 liability 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. Finally, future federal and/or state restrictions, caps, or taxes on GHG emissions that may be passed in response to climate change or hydraulic fracturing concerns may impose additional capital investment requirements, increase our operating costs and reduce the demand for our services.

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 will be 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 a significant number of 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 or 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 will depend, 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 our special committee 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 a 91.0% 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.
- 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.
- 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.

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- 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 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 purchase or construct such assets or to engage in such business opportunities. 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 included provisions in its and our contractual arrangements that limit its liability under contractual arrangements 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 distribute all of our available cash to our unitholders and will 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 will 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 will be 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 sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding common units voting together as a single class is required to remove our general partner. As of February 24, 2014, WGP owned a 41.9% limited partner interest in us. AMM, a subsidiary of Anadarko, separately owned a 0.4% limited partner interest in us.

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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 units held by a person 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 24, 2014, WGP held 49,296,205 common units and AMM separately held 449,129 common units. 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 24, 2014, WGP owned a 41.9% limited partner interest in us, and AMM separately owned a 0.4% limited partner interest in us.

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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 securities analysts' recommendations regarding Anadarko or us and their estimates of Anadarko's and our financial performance;
- 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. A publicly traded partnership such as ours may 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, 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 with respect to our treatment as a partnership for federal income tax purposes or any other tax matter affecting us.

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 ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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.

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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, from time to time members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. 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 expectation for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

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.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not our unitholders 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 liability that results from that income.

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

If a unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized and that unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease in that unitholder's tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to that unitholder, if that unitholder sells such units at a price greater than that unitholder's tax basis in those units, even if the price received is less than 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.

Investment 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 will be reduced by withholding taxes, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Any tax-exempt entity or a non-U.S. person should consult its tax advisor before investing in our common units.

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

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

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between our general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between our general partner and certain of our unitholders.
A successful IRS challenge to these methods or allocations could adversely affect the 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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A unitholder whose common units are the subject of a securities loan (i.e., 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.

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 our 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. Our termination would, among other things, result in the closing of our taxable year, which would require us to file two tax returns (and could result in our unitholders receiving two K-1 Schedules) for one calendar year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a 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, we would be treated as a new partnership for 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 recently 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. We currently own assets and conduct business in the states of Colorado, Kansas, Oklahoma, Pennsylvania, Texas, Utah and Wyoming. Each of these states, other than Texas and Wyoming, currently imposes a personal income tax, and all of these states, except Wyoming, impose income taxes on corporations and other entities. 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.

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Item 3. Legal Proceedings

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 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. In July 2013, Kerr-McGee Gathering LLC, a wholly owned subsidiary of the Partnership, entered into a Compliance Order on Consent with the Colorado Department of Public Health and Environment and paid a $125,000 fine with respect to air emission violations at the Partnership's Frederick Compressor Station.

Item 4. Mine Safety Disclosures

Not applicable.

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
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	$0.60	$0.58	$0.56	$0.54
2012				
High Price	$53.17	$51.28	$47.50	$47.97
Low Price	$45.10	$43.29	$41.15	$38.94
Distribution per common unit	$0.52	$0.50	$0.48	$0.46

As of February 24, 2014, there were 25 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 2,400,467 general partner units for which there is no established public trading market. All general partner units are held by our general partner. See the caption Selected Information from Our Partnership Agreement within this Item 5.

OTHER SECURITIES MATTERS

Unregistered sales of equity securities and use of proceeds. In connection with common units issued through our Continuous Offering Program, our general partner purchased 13,822 general partner units for $0.8 million in cash during the three months ended December 31, 2013, to maintain its 2.0% general partner interest in us. Proceeds from the Continuous Offering Program, including from the sale of the general partner units, were used for general partnership purposes, including the funding of capital expenditures. The general partner units were issued in reliance on an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended.

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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 2,139,027 units remain available for future issuance as of December 31, 2013. 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.

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, minimum quarterly distributions and IDRs.

Available cash. The partnership agreement requires the Partnership to distribute all of its 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 the 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 (such as the Chipeta LLC agreement); 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.

General partner interest and incentive distribution rights. The general partner is currently entitled to 2.0% of all quarterly distributions that the Partnership makes prior to its liquidation. The Partnership's general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.300	98.0%	2.0%
First target distribution	up to $0.345	98.0%	2.0%
Second target distribution	above $0.345 up to $0.375	85.0%	15.0%
Third target distribution	above $0.375 up to $0.450	75.0%	25.0%
Thereafter	above $0.450	50.0%	50.0%

The table above assumes that our general partner maintains its 2.0% general partner interest and that our general partner continues to own the IDRs. The maximum distribution sharing percentage of 50.0% includes distributions paid to the general partner on its 2.0% general partner interest and does not include any distributions that the general partner may receive on common units that it owns or may acquire.

Item 6. Selected Financial and Operating Data

Unless the context otherwise requires, references to "we," "us," "our," the "Partnership" or "Western Gas Partners" refers 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 consolidated subsidiaries, excluding the Partnership and our general partner, and "affiliates" refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and includes the interests in Fort Union Gas Gathering, LLC ("Fort Union"), White Cliffs Pipeline, LLC ("White Cliffs"), Rendezvous Gas Services, LLC ("Rendezvous"), and Enterprise EF78 LLC (the "Mont Belvieu JV"). "Equity investment throughput" refers to our 14.81% share of Fort Union and 22% share of Rendezvous gross volumes.

References to the “Partnership assets” refer collectively to the assets we owned as of December 31, 2013. Because Anadarko controls us through its ownership and control of WGP, which owns our general partner, each of our acquisitions from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko’s historic carrying value, which did not correlate to the total acquisition price paid by us. Further, after an acquisition of assets from Anadarko, we may be required to recast our financial statements to include the activities of such assets as of the date of common control (see Note 2—Acquisitions in the Notes to the Consolidated Financial Statements under Item 8 of this Form 10-K). 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 assets during the periods reported. For ease of reference, we refer to the historical financial results of the Partnership assets prior to our acquisitions from Anadarko as being “our” historical financial results.

Acquisitions

The following table 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. 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 in both the Liberty and Rome gas gathering systems from a wholly owned subsidiary of Anadarko, Anadarko Marcellus Midstream, L.L.C. (the “Non-Operated Marcellus Interest”). Also in March 2013, we completed the acquisition of a 33.75% interest in the Larry’s Creek, Seely and Warrensville gas gathering systems from a third party (the “Anadarko-Operated Marcellus Interest”). 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.

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 assets of MGR. 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, and (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).

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 Management's Discussion and Analysis of Financial Condition and Results of Operations under Item 7 of this Form 10-K:

thousands except per-unit data, throughput and gross margin per Mcf	Summary Financial Information 2013	2012	2011	2010	2009
Statement of Income Data (for the year ended):					
Total revenues	$1,053,495	$910,587	$869,405	$663,274	$619,764
Costs and expenses	585,937	595,085	510,978	394,606	392,939
Depreciation, amortization and impairments	145,916	120,608	113,133	91,129	90,695
Total operating expenses	731,853	715,693	624,111	485,735	483,634
Operating income	321,642	194,894	245,294	177,539	136,130
Interest income (expense), net	(34,897)	(25,160)	(6,239)	1,449	10,762
Other income (expense), net	1,837	292	(44)	(538)	1,628
Income tax expense (1)	2,630	20,715	32,150	21,517	22,103
Net income	285,952	149,311	206,861	156,933	126,417
Net income attributable to noncontrolling interests	10,816	14,890	14,103	11,005	10,260
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758	$145,928	$116,157
Key Performance Measures (for the year ended):					
Gross margin	$689,210	$574,508	$542,034	$416,798	$380,890
Adjusted EBITDA attributable to Western Gas Partners, LP (2)	457,773	377,929	361,653	264,694	223,635
Distributable cash flow (2)	380,529	309,945	319,294	237,372	203,245
General partner interest in net income (3)	69,633	28,089	8,599	3,067	1,428
Limited partners' interest in net income (3)	200,866	78,897	131,560	111,064	69,980
Net income per common unit (basic and diluted) (3)	$1.83	$0.84	$1.64	$1.66	$1.25
Net income per subordinated unit (basic and diluted) (3)	$—	$—	$1.28	$1.61	$1.24
Distributions per unit	$2.280	$1.960	$1.655	$1.440	$1.260
Balance Sheet Data (at period end):					
Net property, plant and equipment	$3,383,255	$2,717,956	$2,121,152	$1,789,651	$1,746,197
Total assets	4,268,027	3,749,922	2,991,579	2,345,255	2,278,512
Total long-term liabilities	1,497,623	1,284,180	860,092	649,414	568,331
Total equity and partners' capital	$2,579,944	$2,280,436	$2,004,169	$1,613,311	$1,627,818
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	$415,721	$338,026	$312,838	$252,898	$209,345
Investing activities	(1,416,066)	(1,249,942)	(479,722)	(921,398)	(223,128)
Financing activities	681,092	1,105,338	366,369	625,590	47,694
Capital expenditures	$(645,854)	$(638,121)	$(149,717)	$(173,891)	$(121,295)
Operating Data (volumes in MMcf/d):					
Gathering, treating and transportation throughput (4)	1,803	1,601	1,555	1,181	1,229
Processing throughput (5)	1,359	1,187	962	815	808
Equity investment throughput (6)	206	235	198	228	225
Total throughput	3,368	3,023	2,715	2,224	2,262
	168	228	242	197	180

Throughput attributable to noncontrolling interests					
Throughput attributable to Western Gas Partners, LP	3,200	2,795	2,473	2,027	2,082
Gross margin per Mcf [7]	$0.56	$0.52	$0.55	$0.51	$0.46
Gross margin per Mcf attributable to Western Gas Partners, LP [8]	$0.58	$0.54	$0.58	$0.54	$0.48

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(1) Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, on the date of and subsequent to our acquisition of the Partnership assets from Anadarko, except for the Chipeta assets, was subject only to Texas margin tax, while income earned prior to our acquisition of the Partnership assets, except for the Chipeta assets, was subject to federal and state income tax. Income attributable to Chipeta was subject to federal and state income tax prior to June 1, 2008, at which time substantially all of the Chipeta assets were contributed to a non-taxable entity for U.S. federal income tax purposes. See Note 1—Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(2) 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 descriptions 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.

(3) Net income earned on and subsequent to the date of our acquisitions of the Partnership assets is allocated to the general partner and the limited partners, including any subordinated unitholders, in accordance with their respective 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.

(4) Excludes average NGL pipeline volumes of 22 MBbls/d, 25 MBbls/d, 24 MBbls/d, 14 MBbls/d and 11 MBbls/d for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively. Includes 100% of Wattenberg system volumes for all periods presented, throughput beginning March 2013 attributable to the Anadarko-Operated Marcellus Interest, and throughput beginning September 2013 attributable to OTTCO.

(5) Consists of 100% of Chipeta and Hilight system volumes, 100% of the Granger and Red Desert complex volumes, 50% of Newcastle volumes, and throughput beginning March 2011 attributable to the Platte Valley system.

(6) Represents our 14.81% share of Fort Union and 22% share of Rendezvous gross volumes. Excludes 7 MBbls/d, 6 MBbls/d, 4 MBbls/d and 3 MBbls/d of average oil pipeline volumes for the years ended December 31, 2013, 2012, 2011 and 2010, respectively, representing our 10% share of average White Cliffs pipeline volumes (our 0.4% share of White Cliffs volumes for 2009 was not material) and excludes 8 MBbls/d of average fractionated volumes for the year ended December 31, 2013, representing our 25% share of average Mont Belvieu JV volumes.

(7) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total throughput (excluding throughput measured in barrels), including 100% of gross margin and volumes attributable to Chipeta, our 14.81% interest in income and volumes attributable to Fort Union and our 22% interest in income and volumes attributable to Rendezvous. Gross margin also includes 100% of gross margin attributable to our NGL pipelines, our 10% interest in income attributable to White Cliffs, and our 25% interest in income attributable to the Mont Belvieu JV.

(8) Calculated as described in footnote seven above, except also excludes the noncontrolling interest owners' proportionate share of revenues, cost of product and throughput.

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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 a 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" refers 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 consolidated subsidiaries, excluding the Partnership and our general partner, and "affiliates" refers to wholly owned and partially owned 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"), and Enterprise EF78 LLC (the "Mont Belvieu JV"). "Equity investment throughput" refers to our 14.81% share of Fort Union and 22% share of Rendezvous gross volumes.
References to the "Partnership assets" refer collectively to the assets we owned as of December 31, 2013. Because Anadarko controls us through its ownership and control of WGP, which owns our general partner, each of our acquisitions from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets we acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by us. Further, after an acquisition of assets from Anadarko, we may be required to recast our financial statements to include the activities of such assets as of the date of common control (see Note 2—Acquisitions in the Notes to the Consolidated Financial Statements under Item 8 of this Form 10-K). 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 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.

EXECUTIVE SUMMARY

We are an MLP organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently own assets located in East, West and South Texas, the Rocky Mountains (Colorado, Utah and Wyoming), north-central Pennsylvania, and the Mid-Continent (Kansas and Oklahoma), 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, 2013, our assets, exclusive of our interests in Fort Union, White Cliffs, Rendezvous and the Mont Belvieu JV accounted for under the equity method, consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests
Natural gas gathering systems	13	1	5
Natural gas treating facilities	8	—	—
Natural gas processing facilities	8	3	—
NGL pipelines	3	—	—
Natural gas pipelines	3	—	—

See also Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Significant financial and operational highlights during the year ended December 31, 2013 included the following:

- We issued $250.0 million aggregate principal amount of 2.600% Senior Notes due 2018. Net proceeds were used to repay amounts then outstanding under our revolving credit facility. See Liquidity and Capital Resources within this Item 7 for additional information.

- We completed construction and commenced operations in June 2013 of the 200 MMcf/d Brasada processing and stabilization facility in the Eagleford shale area of South Texas.

- We announced a project to expand the processing capacity at our Lancaster plant by another 300 MMcf/d with a second cryogenic processing train. The expansion project is currently under construction.

- We completed the following acquisitions: (i) Anadarko’s 33.75% interest (non-operated) in the Liberty and Rome gas gathering systems in north-central Pennsylvania, (ii) a third party’s 33.75% interest (operated by Anadarko) in each of the Larry’s Creek, Seely and Warrensville gas gathering systems, also in north-central Pennsylvania, (iii) a 25% interest in the Mont Belvieu JV, an entity formed to design, construct and own two NGL fractionation trains located in Mont Belvieu, Texas, and (iv) Overland Trail Transmission, LLC, which owns and operates a natural gas pipeline connecting our Red Desert and Granger complexes in southwestern Wyoming. See Acquisitions under Items 1 and 2 of this Form 10-K for additional information.

- We issued 12,200,735 common units to the public, generating net proceeds of $740.3 million, including the general partner’s proportionate capital contribution to maintain its 2.0% general partner interest. Net proceeds were used to repay a portion of the amount outstanding under our revolving credit facility, with the remaining net proceeds used for general partnership purposes, including the funding of capital expenditures.

- We raised our distribution to $0.60 per unit for the fourth quarter of 2013, representing a 3% increase over the distribution for the third quarter of 2013, a 15% increase over the distribution for the fourth quarter of 2012, and our nineteenth consecutive quarterly increase.

Significant operational highlights during the year ended December 31, 2013 included the following:

- Throughput attributable to Western Gas Partners, LP totaled 3,200 MMcf/d for the year ended December 31, 2013, representing a 14% increase compared to the year ended December 31, 2012.

- Gross margin (total revenues less cost of product) attributable to Western Gas Partners, LP averaged $0.58 per Mcf for the year ended December 31, 2013, representing a 7% increase compared to the year ended December 31, 2012.

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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, 2013, 79% of our total revenues and 57% of our throughput (excluding equity investment throughput and revenues) were attributable to transactions with Anadarko.

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.

We received significant dedications from our largest customer, Anadarko, solely with respect to our Wattenberg, Dew, Pinnacle, Haley, Helper, Clawson and Hugoton gathering systems. Specifically, pursuant to the terms of our applicable gathering agreements, Anadarko has dedicated to us all of the natural gas production it owns or controls from (i) wells that are currently connected to such gathering systems, and (ii) additional wells that are drilled within one mile of wells connected to such gathering systems, as those systems currently exist and as they are expanded to connect additional wells in the future. As a result, this dedication will continue to expand as long as additional wells are connected to these gathering systems.

For the year ended December 31, 2013, 74% 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 and Rendezvous.

For the year ended December 31, 2013, 26% 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, 2013, 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. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements included 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 2013, 2012 and 2011 as compared to future periods. Please see the caption Items Affecting the Comparability of Our Financial Results, set forth below in this Item 7.

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) gross margin, (3) operating and maintenance expenses, (4) general and administrative expenses, (5) Adjusted EBITDA (as defined below) and (6) Distributable cash flow (as defined below).

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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 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, 2013, we added 273 receipt points to our systems.

Gross margin. We define gross margin as total revenues less cost of product. We consider gross margin to provide information useful in assessing our results of operations and our ability to internally fund capital expenditures and to service or incur additional debt. 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 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.

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. General and administrative expenses for periods prior to our acquisition of the Partnership assets include amounts attributable to costs incurred on our behalf and allocations of general and administrative costs by Anadarko and the general partner to us. 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 agreement and omnibus agreement. 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 EBITDA. We define “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 estimated cash flows 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.

Reconciliation to GAAP measures. Adjusted EBITDA and Distributable cash flow are not defined in generally accepted accounting principles in the United States (“GAAP”). The GAAP measures most directly comparable to Adjusted EBITDA are net income attributable to Western Gas Partners, LP and net cash provided by operating activities, and the GAAP measure most directly comparable to Distributable cash flow is net income attributable to Western Gas Partners, LP. Our non-GAAP financial measures of Adjusted EBITDA and Distributable cash flow should not be considered as alternatives to the GAAP measures of 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 EBITDA and Distributable cash flow have important limitations as analytical tools because they exclude some, but not all, items that affect net income and net cash provided by operating activities. 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 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 EBITDA and Distributable cash flow as analytical tools by reviewing the comparable GAAP measures, understanding the differences between Adjusted EBITDA and Distributable cash flow compared to (as applicable) 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.

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The following tables present (a) 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 (b) 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	2013	2012	2011
Reconciliation of Adjusted EBITDA to Net income attributable to Western Gas Partners, LP			
Adjusted EBITDA attributable to Western Gas Partners, LP	$457,773	$377,929	$361,653
Less:			
Distributions from equity investees	22,136	20,660	15,999
Non-cash equity-based compensation expense (1)	3,575	73,508	13,754
Interest expense	51,797	42,060	30,345
Income tax expense	4,431	20,715	32,150
Depreciation, amortization and impairments (2)	143,375	118,279	110,380
Other expense (2)	175	1,665	3,683
Add:			
Equity income, net	23,732	16,111	11,261
Interest income, net – affiliates	16,900	16,900	24,106
Other income (2) (3)	419	368	2,049
Income tax benefit	1,801	—	—
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Reconciliation of Adjusted EBITDA to Net cash provided by operating activities			
Adjusted EBITDA attributable to Western Gas Partners, LP	$457,773	$377,929	$361,653
Adjusted EBITDA attributable to noncontrolling interests	13,348	17,214	16,850
Interest income (expense), net	(34,897)	(25,160)	(6,239)
Non-cash equity based compensation expense (1)	(54)	(69,791)	(10,264)
Debt-related amortization and other items, net	2,449	2,319	3,110
Current income tax (benefit) expense	(2,944)	9,398	(15,570)
Other income (expense), net (3)	253	(1,292)	(1,628)
Distributions from equity investees less than (in excess of) equity income, net	1,596	(4,549)	(4,738)
Changes in operating working capital:			
Accounts receivable and natural gas imbalance receivable	(35,934)	23,520	(47,415)
Accounts payable, accrued liabilities and natural gas imbalance payable	21,952	5,045	30,884
Other	(7,821)	3,393	(13,805)
Net cash provided by operating activities	$415,721	$338,026	$312,838
Cash flow information of Western Gas Partners, LP			
Net cash provided by operating activities	$415,721	$338,026	$312,838
Net cash used in investing activities	$(1,416,066)	$(1,249,942)	$(479,722)
Net cash provided by financing activities	$681,092	$1,105,338	$366,369

(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. See Note 2—Acquisitions in

the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(3) Excludes income of $1.6 million for each of the years ended December 31, 2013, 2012 and 2011, 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, 2013	2012	2011
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP and calculation of the Coverage ratio			
Distributable cash flow	$380,529	$309,945	$319,294
Less:			
Distributions from equity investees	22,136	20,660	15,999
Non-cash equity-based compensation expense (1)	3,575	73,508	13,754
Interest expense, net (non-cash settled)	—	326	—
Income tax expense	2,630	20,715	32,150
Depreciation, amortization and impairments (2)	143,375	118,279	110,380
Other expense (1)	175	1,665	3,683
Add:			
Equity income, net	23,732	16,111	11,261
Cash paid for maintenance capital expenditures (2) (3)	29,850	36,459	28,304
Capitalized interest	11,945	6,196	420
Cash paid for income taxes	552	495	190
Other income (2) (4)	419	368	2,049
Interest income, net (non-cash settled)	—	—	7,206
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Distributions declared (5)			
Limited partners	$255,308		
General partner	70,745		
Total	$326,053		
Coverage ratio	1.17 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) Excludes income of $1.6 million for each of the years ended December 31, 2013, 2012 and 2011, related to a component of a gas processing agreement accounted for as a capital lease. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(5) Reflects distributions of $2.28 per unit declared for the year ended December 31, 2013.

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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 allow for rate resets that target a return on invested capital in those assets over the life of the agreement. Effective July 1, 2010, contracts covering all of Wattenberg's affiliate throughput were converted from primarily keep-whole contracts into a 10-year fee-based agreement. This contract change impacts the comparability of the consolidated statements of income and cash flows. In addition, in connection with the MGR acquisition, we entered into 10-year, fee-based gathering and processing agreements with Anadarko effective December 1, 2011, for all affiliate throughput on the MGR assets. 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 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 Granger, Hilight, Hugoton, Newcastle, MGR and Wattenberg assets, with various expiration dates through December 2016. In December 2013, we extended the commodity price swap agreements for the Hilight and Newcastle assets through December 2014. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Income taxes. Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, on and subsequent to the date of the acquisition of the Partnership assets, is subject only to Texas margin tax.
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 representing the general and administrative expenses 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	2013	2012	2011
General and administrative expenses	$16,882	$14,904	$11,754
Public company expenses	7,152	6,830	7,735
Total reimbursement	$24,034	$21,734	$19,489

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. 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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Interest on intercompany balances. For periods prior to our acquisition of the Partnership assets from Anadarko, except for Chipeta, we incurred interest expense or earned interest income on current intercompany balances with Anadarko related to such assets. These intercompany balances were extinguished through non-cash transactions in connection with the closing of our IPO, the Powder River acquisition, the Chipeta acquisition, the Granger acquisition, the Wattenberg acquisition, the acquisition of a 0.4% interest in White Cliffs, the Bison acquisition, the MGR acquisition and the Non-Operated Marcellus Interest acquisition. Therefore, interest expense and interest income attributable to these balances are reflected in our historical consolidated financial statements for the periods ending prior to our acquisition of the Partnership assets, except for Chipeta. Chipeta cash settles its transactions directly with third parties and Anadarko, as well as with the other subsidiaries of the Partnership.
Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on the aforementioned assets prior to their acquisition were entirely settled through an adjustment to net investment by Anadarko.

Platte Valley acquisition. In February 2011, we acquired a natural gas gathering system and cryogenic gas processing facilities, collectively referred to as the “Platte Valley assets,” financed with borrowings under our $800.0 million senior unsecured revolving credit facility (“RCF”). These assets, acquired from a third-party, 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 Platte Valley assets have been included in our consolidated statements of income beginning on the acquisition date in the first quarter of 2011.
The fair values of the plant and processing facilities, related equipment, and intangible assets acquired were based on the market, cost and income approaches. The liabilities assumed include certain amounts associated with environmental contingencies estimated by management. All fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. See Note 1—Summary of Significant Accounting Policies, Note 2—Acquisitions and Note 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K for further information.

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.

Execution of Construction, Ownership and Operation Agreement for the Non-Operated Marcellus Interest. In March 2013, we completed the acquisition of the Non-Operated Marcellus Interest. Anadarko and a third party entered into a 50/50 Joint Exploration Agreement, dated September 1, 2006, covering counties in north-central Pennsylvania within an Area of Mutual Interest that the parties designated as “Area A.” Initial construction of the midstream assets within Area A began in May 2008, and limited gathering services were provided to producers in 2008, 2009 and 2010, with the midstream assets becoming fully operational in 2011. In December 2011, following various sales of interests, AMM and three third-party owners entered into a Construction, Ownership and Operation agreement (the “COO Agreement”) to jointly own and develop the midstream assets in Area A (the “AMI Assets”). Deferred revenues and expenses associated with the third-party operation of the AMI Assets were recognized in 2011 upon the execution of the COO Agreement.

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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 natural gas and NGL prices. The relatively low natural gas price environment, which has persisted over the past three years, has led to lower levels of drilling activity in areas served by certain of our assets. Several of our customers, including Anadarko, have reduced activity levels in certain areas, shifting capital toward liquid-rich opportunities that offer higher margins and superior economics to producers. 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.

Changes in regulations. Our operations and the operations of our customers have been, and at times in the future may be, affected by political developments and are subject to 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/or 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.

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. Recent 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 U.S. 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 2013. 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.

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Acquisition opportunities. As of December 31, 2013, Anadarko's total domestic midstream asset portfolio, excluding the assets we own, consisted of 16 gathering systems, 6,259 miles of pipeline and 10 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, 2013, WGP held a 41.2% limited partner interest in us, and through its ownership of our general partner, WGP indirectly held a 2.0% general partner interest in us and 100% of our incentive distribution rights. As of December 31, 2013, Anadarko Marcellus Midstream, L.L.C. ("AMM"), a subsidiary of Anadarko, separately held a 0.4% limited partner interest in us. 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 acquire or construct those assets. 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.

Other. There is uncertainty related to the ultimate outcome of the Tronox Adversary Proceeding (as defined and described in Note 17—Contingencies—Tronox Litigation in the Notes to the Consolidated Financial Statements under Item 8 of Anadarko's Form 10-K for the year ended December 31, 2013, which is not, and shall not be deemed to be, incorporated by reference herein), and such outcome's ultimate impact on Anadarko and us.

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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	2013	2012	2011
Gathering, processing and transportation of natural gas and natural gas liquids	$482,542	$382,330	$347,469
Natural gas, natural gas liquids and condensate sales	541,244	508,339	502,383
Equity income and other, net	29,709	19,918	19,553
Total revenues (1)	1,053,495	910,587	869,405
Total operating expenses (1)	731,853	715,693	624,111
Operating income	321,642	194,894	245,294
Interest income, net – affiliates	16,900	16,900	24,106
Interest expense	(51,797)	(42,060)	(30,345)
Other income (expense), net	1,837	292	(44)
Income before income taxes	288,582	170,026	239,011
Income tax expense	2,630	20,715	32,150
Net income	285,952	149,311	206,861
Net income attributable to noncontrolling interests	10,816	14,890	14,103
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Key performance metrics (2)			
Gross margin	$689,210	$574,508	$542,034
Adjusted EBITDA attributable to Western Gas Partners, LP	$457,773	$377,929	$361,653
Distributable cash flow	$380,529	$309,945	$319,294

(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) Gross margin, Adjusted EBITDA 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 EBITDA 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, 2013" refer to the comparison of the year ended December 31, 2013, to the year ended December 31, 2012, and any increases or decreases "for the year ended December 31, 2012" refer to the comparison of the year ended December 31, 2012, to the year ended December 31, 2011.

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Throughput

MMcf/d	Year Ended December 31, 2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Gathering, treating and transportation [1]	1,803	1,601	13 %	1,555	3 %
Processing [2]	1,359	1,187	14 %	962	23 %
Equity investment [3]	206	235	(12)%	198	19 %
Total throughput [4]	3,368	3,023	11 %	2,715	11 %
Throughput attributable to noncontrolling interests	168	228	(26)%	242	(6)%
Total throughput attributable to Western Gas Partners, LP	3,200	2,795	14 %	2,473	13 %

(1) Excludes average NGL pipeline volumes of 22 MBbls/d, 25 MBbls/d and 24 MBbls/d for the years ended December 31, 2013, 2012 and 2011, respectively. Includes 100% of Wattenberg system volumes for all periods presented, throughput beginning March 2013 attributable to the Anadarko-Operated Marcellus Interest, and throughput beginning September 2013 attributable to the Overland Trail Transmission, LLC ("OTTCO").

(2) Consists of 100% of Chipeta, Hilight and Platte Valley system volumes, 100% of the Granger and Red Desert complex volumes, and 50% of Newcastle volumes.

(3) Represents our 14.81% share of Fort Union and 22% share of Rendezvous gross volumes. Excludes our 10% share of average White Cliffs pipeline volumes consisting of 7 MBbls/d, 6 MBbls/d and 4 MBbls/d for the years ended December 31, 2013, 2012 and 2011, respectively, and for the year ended December 31, 2013, excludes 8 MBbls/d of average fractionated volumes, representing our 25% share of average fractionated Mont Belvieu JV volumes.

(4) Includes affiliate, third-party and equity-investment volumes (as equity-investment volumes are defined in the above footnote).

Gathering, treating and transportation throughput increased by 202 MMcf/d for the year ended December 31, 2013, due to increased volumes at the Non-Operated Marcellus Interest and additional throughput from the Anadarko-Operated Marcellus Interest beginning in March 2013. These increases were partially offset by decreases at the Bison facility resulting from reduced drilling activity in the area and at MIGC due to the expiration of a firm transportation agreement effective September 2012.

Gathering, treating and transportation throughput increased by 46 MMcf/d for the year ended December 31, 2012, primarily due to increased volumes at the Non-Operated Marcellus Interest. This increase was partially offset by throughput decreases at the Pinnacle and Dew systems resulting from natural production declines in those areas, throughput decreases at MIGC due to the September 2012 expiration of a firm transportation agreement, and throughput decreases at the Bison facility resulting from reduced drilling activity in the area driven by unfavorable producer economics.

Processing throughput increased by 172 MMcf/d for the year ended December 31, 2013, primarily due to throughput increases at Chipeta, the start-up of the Brasada facility 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 a plant included in the MGR acquisition ("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.

Processing throughput increased by 225 MMcf/d for the year ended December 31, 2012, primarily due to volumes processed under a new contract effective January 2012 at the Granger straddle plant compared to no such volumes in the comparable period, and throughput increases at the Chipeta system resulting from increased drilling activity.

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. Equity investment volumes increased by 37 MMcf/d for the year ended December 31, 2012, resulting from higher throughput at the Fort Union system due to producers choosing to route additional gas to reach desired end markets and at the Rendezvous system due to increased third-party drilling activity.

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Natural Gas Gathering, Processing and Transportation Revenues

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Gathering, processing and transportation of natural gas and natural gas liquids	$482,542	$382,330	26 %	$347,469	10 %

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 at the Non-Operated Marcellus Interest, the Wattenberg system, and Chipeta, respectively, all due to higher throughput, an increase of $14.1 million due to the addition of the Anadarko-Operated Marcellus Interest beginning in March 2013, and an increase of $16.3 million due to the start-up of the Brasada facility in June 2013.
Revenues from gathering, processing and transportation of natural gas and natural gas liquids increased by $34.9 million for the year ended December 31, 2012, primarily due to increases of $15.0 million and $13.4 million at the Non-Operated Marcellus Interest and Chipeta system, respectively, due to increased volumes, and a $13.6 million increase at the Wattenberg system due to increased gathering rates and volumes. These increases were partially offset by decreased revenue of $3.0 million at the Helper system due to a downward rate revision effective April 1, 2012, decreased revenue of $3.0 million at MIGC due to the expiration of firm transportation agreements, and decreased revenue of $2.4 million at the Granger system due to diverted volumes.

Natural Gas, Natural Gas Liquids and Condensate Sales

	Year Ended December 31,				
thousands except percentages and per-unit amounts	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Natural gas sales	$118,134	$101,116	17 %	$129,939	(22)%
Natural gas liquids sales	391,608	377,377	4 %	345,375	9 %
Drip condensate sales	31,502	29,846	6 %	27,069	10 %
Total	$541,244	$508,339	6 %	$502,383	1 %
Average price per unit:					
Natural gas (per Mcf)	$4.58	$4.24	8 %	$5.32	(20)%
Natural gas liquids (per Bbl)	$47.69	$48.22	(1)%	$47.44	2 %
Drip condensate (per Bbl)	$76.62	$75.88	1 %	$73.60	3 %

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, which consisted of a $17.0 million increase in sales of natural gas, 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 Wattenberg system and the Red Desert complex, partially offset by a decrease at the Platte Valley system 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 Wattenberg system 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 Platte Valley system 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 Wattenberg system due to an increase in condensate volumes sold as a result of increased throughput,

partially offset by a $0.9 million decrease at Hugoton due to a decrease in condensate volumes sold as a result of decreased throughput.

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Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $6.0 million for the year ended December 31, 2012, which consisted of a $32.0 million increase in NGLs sales and a $2.8 million increase in drip condensate sales, partially offset by a $28.8 million decrease in natural gas sales.

The growth in NGLs sales for the year ended December 31, 2012, was primarily due to increases of $10.3 million, $9.2 million, and $3.1 million resulting from higher volumes sold at the Chipeta, Hilight, and Wattenberg systems, respectively; increases of $5.1 million and $2.3 million at the Granger system and Red Desert complex, respectively, due to increased pricing, which was offset by a decrease in volumes; and an increase of $9.6 million related to volumes processed at the Granger straddle plant under a new contract effective January 2012, with no volumes in the comparable period. These increases were partially offset by an $8.5 million price-related decrease at the Platte Valley system.

The increase in drip condensate sales for the year ended December 31, 2012, was primarily due to a $2.9 million increase at the Wattenberg system and a $0.7 million increase at the Platte Valley system, both resulting from increased volumes. These increases were partially offset by a $0.8 million decrease at the Hugoton system as a result of lower volumes.

The decrease in natural gas sales for the year ended December 31, 2012, was primarily due to a 20% decrease in overall natural gas sales prices and lower sales volumes, resulting in decreases of $17.0 million at the Hilight system, $3.8 million at the Red Desert complex, and $2.7 million at the Wattenberg system. Also contributing to the overall decrease in natural gas sales was a decline at the Platte Valley system of $3.2 million resulting from price decreases, partially offset by an increase in volumes sold.

For the years ended December 31, 2013 and 2012, average natural gas, NGL and drip condensate prices include the effects of commodity price swap agreements attributable to sales for the Granger, Hilight, Newcastle, Hugoton and Wattenberg systems, and the MGR assets. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Equity Income and Other Revenues

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Equity income	$23,732	$16,111	47 %	$11,261	43 %
Other revenues, net	5,977	3,807	57 %	8,292	(54)%
Total	$29,709	$19,918	49 %	$19,553	2 %

For the year ended December 31, 2013, equity income increased by $7.6 million, primarily due to the fourth quarter 2013 startup of the Mont Belvieu JV fractionation trains, and volume increases at White Cliffs. Equity income increased by $4.9 million for the year ended December 31, 2012, primarily due to a $3.8 million increase in income from White Cliffs and a $0.7 million increase in income from Rendezvous as a result of increased volumes.

Other revenues, net increased by $2.2 million for the year ended December 31, 2013, primarily due to the collection of deficiency fees associated with volume commitments at Chipeta. Other revenues, net decreased by $4.5 million for the year ended December 31, 2012, primarily due to indemnity fees associated with volume commitments received in the prior year at the Red Desert complex and Hugoton system, with no comparable activity in the current period, along with changes in gas imbalance positions at the Wattenberg and Hilight systems.

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Cost of Product and Operation and Maintenance Expenses

thousands except percentages	Year Ended December 31, 2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Cost of product	$364,285	$336,079	8 %	$327,371	3 %
Operation and maintenance	168,657	140,106	20 %	126,464	11 %
Total cost of product and operation and maintenance expenses	$532,942	$476,185	12 %	$453,835	5 %

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 Wattenberg system and the Red Desert complex, partially offset by decreases at the Platte Valley system and the Granger complex; and

- a $10.7 million net increase in NGL purchases primarily at the Red Desert complex, the Hilight system, and the Wattenberg system, partially offset by decreases at Chipeta, the Platte Valley system, and the Granger complex.

Including the effects of commodity price swap agreements on purchases, cost of product expense for the year ended December 31, 2012, increased by $8.7 million primarily due to the following:

- a $22.8 million net increase in NGL purchases primarily at Chipeta, the Hilight system, and the Wattenberg system due to volume fluctuations noted in Throughput and Natural Gas, Natural Gas Liquids and Condensate Sales within this Item 7, and an increase for the MGR assets as a result of entering into commodity price swap agreements that became effective in January 2012, partially offset by a decrease at the Platte Valley system due to lower pricing subsequent to its acquisition in February 2011; and

- a $12.6 million net decrease in residue purchases at the Hilight system due to declines in residue purchase prices, partially offset by an increase in cost of product expense for residue purchases for the MGR assets as a result of entering into commodity price swap agreements that became effective in January 2012.

Cost of product expense for the years ended December 31, 2013 and 2012, includes the effects of commodity price swap agreements attributable to purchases for the Granger, Hilight, Hugoton, Newcastle and Wattenberg systems, and the MGR assets. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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, an increase of $8.3 million for plant repairs and maintenance primarily at the Wattenberg system and Chipeta, and an increase of $7.7 million for salaries, wages and payroll tax expense primarily at the Wattenberg system, the Brasada facility and the Hilight system.

Operation and maintenance expense increased by $13.6 million for the year ended December 31, 2012, primarily due to increased contract labor expense of $5.1 million at the Platte Valley and Wattenberg systems, increased expense of $1.1 million related to general equipment for operations and increased maintenance expense at the Wattenberg system, increased expense of $1.7 million related to plant repairs and turnaround expenses at the Bison facility and Hilight system, and increased facility expense of $0.8 million for the Non-Operated Marcellus Interest.

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General and Administrative, Depreciation and Other Expenses

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
General and administrative	$29,751	$99,212	(70)%	$40,564	145 %
Property and other taxes	23,244	19,688	18 %	16,579	19 %
Depreciation, amortization and impairments	145,916	120,608	21 %	113,133	7 %
Total general and administrative, depreciation and other expenses	$198,911	$239,508	(17)%	$170,276	41 %

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.

General and administrative expenses increased by $58.6 million for the year ended December 31, 2012, due to an increase of $59.8 million in non-cash compensation expenses primarily attributable to the increase in the value of the outstanding awards under the Incentive Plan from $634.00 per Unit Appreciation Right ("UAR") to $2,745.00 per UAR and the related increase of $1.2 million in payroll taxes. In addition, corporate and management personnel costs for which we reimbursed Anadarko pursuant to our omnibus agreement increased $3.6 million. These increases were partially offset by a $3.9 million decrease in management fees allocated to the Bison and MGR assets, the agreements for which were discontinued as of the respective dates of contribution, and a $1.2 million decrease in consulting and audit fees.

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 Platte Valley, Chipeta and Wattenberg systems and $0.9 million due to the completion of the Brasada facility in June 2013. Property and other taxes increased by $3.1 million for the year ended December 31, 2012, primarily due to ad valorem tax increases at the Platte Valley and Wattenberg assets.

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 Wattenberg, Chipeta, Platte Valley and Hilight systems, a $6.2 million increase in depreciation and impairment expense associated with the Non-Operated Marcellus Interest, a $6.1 million increase in depreciation expense related to the completion of the Brasada facility in June 2013, and a $3.9 million increase in depreciation expense associated with the March 2013 acquisition of the Anadarko-Operated Marcellus Interest. 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, as compared to the $6.6 million impairment recognized in 2012 related to a gathering system in central Wyoming and a relocated compressor.

Depreciation, amortization and impairments increased by $7.5 million for the year ended December 31, 2012, primarily attributable to the addition of the Platte Valley assets, and depreciation associated with capital projects completed at the Wattenberg, Hilight, and Chipeta systems, the Non-Operated Marcellus Interest, and the Red Desert complex, partially offset by a $3.9 million decrease in impairment expense. The decrease is primarily due to a $6.6 million impairment recognized during 2012 related to a gathering system in central Wyoming and a relocated compressor, as compared to $10.3 million in impairment expense recognized during 2011, related to an indefinitely postponed expansion project at the Red Desert complex and a pipeline included in the MGR acquisition. See Note 7—Property, Plant and Equipment in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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Interest Income, Net – Affiliates and Interest Expense

Amortization of debt issuance costs and commitment fees in the table below includes amortization of (i) the original issue discount for the June 2012 offering of $520.0 million aggregate principal amount of 4.000% Senior Notes due 2022, (ii) the original issue premium for the October 2012 offering of an additional $150.0 million in aggregate principal amount of 4.000% Senior Notes due 2022, (iii) the original issue discount for the $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the "2021 Notes"), (iv) the original issue discount for the August 2013 offering of $250.0 million aggregate principal amount of 2.600% Senior Notes due 2018 (the "2018 Notes"), and (v) underwriters' fees. The October 2012 notes and the June 2012 notes were issued under the same indenture and are considered a single class of securities, collectively referred to as the "2022 Notes."

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Interest income on note receivable	$16,900	$16,900	— %	$16,900	— %
Interest income, net on affiliate balances [1]	—	—	— %	7,206	(100)%
Interest income, net – affiliates	$16,900	$16,900	— %	$24,106	(30)%
Third parties					
Interest expense on long-term debt	$(59,293)	$(41,171)	44 %	$(20,533)	101 %
Amortization of debt issuance costs and commitment fees [2]	(4,449)	(4,319)	3 %	(5,297)	(18)%
Capitalized interest	11,945	6,196	93 %	420	NM
Affiliates					
Interest expense on note payable to Anadarko [3]	—	(2,440)	(100)%	(4,935)	(51)%
Interest expense on affiliate balances [4]	—	(326)	(100)%	—	NM
Interest expense	$(51,797)	$(42,060)	23 %	$(30,345)	39 %

NM-Not meaningful

(1) Incurred on affiliate balances related to the Non-Operated Marcellus Interest, the MGR assets, and the Bison assets for periods prior to the acquisition of such assets. Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on the Partnership assets prior to their acquisition were entirely settled through an adjustment to net investment by Anadarko.

(2) For the year ended December 31, 2013, includes $1.2 million of amortization of debt issuance costs and underwriters' fees for the 2022 Notes, the 2021 Notes, and the 2018 Notes. For the year ended December 31, 2012, includes $1.1 million of amortization of debt issuance costs and underwriters' fees for the 2022 Notes and the 2021 Notes.

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

(4) Imputed interest expense on the reimbursement payable to Anadarko for certain expenditures incurred in 2011 related to the construction of the Brasada facility and Lancaster plant. In the fourth quarter of 2012, we repaid the reimbursement payable to Anadarko associated with the construction of the Brasada facility and Lancaster plant. See Note 5—Transactions with Affiliates 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 current 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 10—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.

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Interest expense increased by $11.7 million for the year ended December 31, 2012, primarily due to interest expense incurred on the $670.0 million aggregate principal amount of the 2022 Notes, partially offset by increased capitalized interest associated with the construction of a second cryogenic train at the Chipeta plant and a decrease in interest expense on the note payable to Anadarko. See Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Other Income (Expense), Net

	Year Ended December 31,				
thousands	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Other income (expense), net	$1,837	$292	NM	$(44)	NM

For the year ended December 31, 2013 and 2012, other income (expense), net included $1.6 million of interest income related to the capital lease component of a processing agreement assumed in connection with the MGR acquisition. In addition, for the year ended December 31, 2013, other income (expense), net included $0.5 million of interest earned on overnight investments, which was offset by $0.2 million of expense associated with a remediation project for MGR.
For the year ended December 31, 2012, other income (expense), net also included a realized loss of $1.7 million resulting from U.S. Treasury Rate lock agreements settled simultaneously with our June 2012 offering of the 2022 Notes. See Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Income Tax Expense

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Income before income taxes	$288,582	$170,026	70 %	$239,011	(29)%
Income tax expense	2,630	20,715	(87)%	32,150	(36)%
Effective tax rate	1 %	12 %		13 %	

We are not a taxable entity for U.S. federal income tax purposes; however, 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 Non-Operated Marcellus Interest prior to and including March 2013, (b) the MGR assets prior to and including January 2012 and (c) the Bison assets prior to and including June 2011, was subject to federal and state income tax. Income earned on the Non-Operated Marcellus Interest, MGR assets and Bison assets for periods subsequent to March 2013, January 2012, and June 2011, respectively, was only subject to Texas margin tax on income apportionable to Texas.

Noncontrolling Interests

	Year Ended December 31,				
thousands except percentages	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Net income attributable to noncontrolling interests	$10,816	$14,890	(27)%	$14,103	6 %

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. For the year ended December 31, 2012, net income attributable to noncontrolling interests increased by $0.8 million primarily due to higher volumes at the Chipeta system, partially offset by the acquisition of the additional Chipeta interest in August 2012. See Note 2—Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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KEY PERFORMANCE METRICS

	Year Ended December 31,					
thousands except percentages and gross margin per Mcf	2013	2012	Inc/ (Dec)	2011	Inc/ (Dec)
Gross margin	$689,210	$574,508	20 %	$542,034	6 %
Gross margin per Mcf (1)	0.56	0.52	8 %	0.55	(5)%
Gross margin per Mcf attributable to Western Gas Partners, LP (2)	0.58	0.54	7 %	0.58	(7)%
Adjusted EBITDA attributable to Western Gas Partners, LP (3)	457,773	377,929	21 %	361,653	5 %
Distributable cash flow (3)	$380,529	$309,945	23 %	$319,294	(3)%

(1) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total throughput (excluding throughput measured in barrels), including 100% of gross margin and volumes attributable to Chipeta, our 14.81% interest in income and volumes attributable to Fort Union and our 22% interest in income and volumes attributable to Rendezvous. Gross margin also includes 100% of gross margin attributable to our NGL pipelines, our 10% interest in income attributable to White Cliffs, and our 25% interest in income attributable to the Mont Belvieu JV.

(2) Calculated as described in footnote one above, except also excludes the noncontrolling interest owners' proportionate share of revenues, cost of product and throughput.

(3) For reconciliations of Adjusted EBITDA 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.

Gross margin and Gross margin per Mcf. Gross margin increased by $114.7 million for the year ended December 31, 2013, primarily due to higher margins on the Non-Operated Marcellus Interest, the Wattenberg system, the Anadarko-Operated Marcellus Interest, Chipeta, and the start-up of the Brasada facility in June 2013.
Gross margin increased by $32.5 million for the year ended December 31, 2012, primarily due to higher margins on the Non-Operated Marcellus Interest and on the Wattenberg and Chipeta systems due to increases in volumes sold (including the impact of commodity price swap agreements at the Wattenberg system). These increases were partially offset by lower gross margins at the Red Desert complex due to higher prices in 2011, as we entered into commodity price swap agreements associated with the MGR acquisition that became effective in January 2012.
Gross margin per Mcf increased by $0.04 for the year ended December 31, 2013, primarily due to higher margins and increases in throughput at Chipeta, the Wattenberg system, and the Non-Operated Marcellus Interest, as well as overall changes in the throughput mix of our portfolio.
Gross margin per Mcf decreased by $0.03 for the year ended December 31, 2012, primarily due to a decrease in volumes sold at the Red Desert complex coupled with an increase in cost of product as a result of commodity price swap agreements associated with the MGR acquisition which became effective in January 2012, partially offset by increases associated with growth in certain of our lower-margin assets.

Adjusted EBITDA. 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 excluding equity income and a $4.1 million decrease in net income attributable to noncontrolling interest 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.
Adjusted EBITDA increased by $16.3 million for the year ended December 31, 2012, primarily due to a $36.3 million increase in total revenues excluding equity income, a $4.7 million increase in distributions from equity investees, and a $1.1 million decrease in general and administrative expenses excluding non-cash equity-based compensation. These increases were partially offset by a $13.6 million increase in operation and maintenance expenses, an $8.7 million

increase in cost of product, a $3.1 million increase in property and other tax expense, and a $0.8 million increase in net income attributable to noncontrolling interests.

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Distributable cash flow. 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.
Distributable cash flow decreased by $9.3 million for the year ended December 31, 2012, primarily due to a $17.2 million increase in net cash paid for interest expense, an $8.2 million increase in cash paid for maintenance capital expenditures and a $0.3 million increase in cash paid for income taxes, partially offset by the $16.3 million increase in Adjusted EBITDA.

LIQUIDITY AND CAPITAL RESOURCES

Our primary cash requirements are for acquisitions and other 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, 2013, 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 20, 2014, the board of directors of our general partner declared a cash distribution to our unitholders of $0.60 per unit, or $92.6 million in aggregate, including incentive distributions. The cash distribution was paid on February 12, 2014, to unitholders of record at the close of business on January 31, 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.

Working capital. As of December 31, 2013, we had $4.4 million of working capital, which we define as the amount by which current assets exceed current liabilities. Working capital is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven by changes in accounts receivable and accounts payable and factors such as credit extended to, and the timing of collections from, our customers, and the level and timing of our spending for maintenance and expansion activity. As of December 31, 2013, we had $787.2 million available for borrowing under our $800.0 million RCF.

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

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

- expansion capital expenditures, which include expenditures to construct new midstream infrastructure and those expenditures incurred in order 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	2013	2012	2011
Acquisitions	$716,985	$611,719	$330,794
Expansion capital expenditures	$615,924	$600,893	$121,318
Maintenance capital expenditures	29,930	37,228	28,399
Total capital expenditures (1)	$645,854	$638,121	$149,717
Capital incurred (2)	$628,285	$690,041	$182,536

(1) Capital expenditures for the years ended December 31, 2013 and 2012, included $10.6 million and $6.8 million, respectively, of capitalized interest. Capital expenditures included the noncontrolling interest owners' share of Chipeta's capital expenditures, funded by contributions from the noncontrolling interest owners for all periods presented. Capital expenditures for the years ended December 31, 2012 and 2011, included $178.8 million and $20.1 million, respectively, of pre-acquisition capital expenditures for the Non-Operated Marcellus Interest, the MGR assets, and the Bison assets.

(2) Includes the noncontrolling interest owners' share of Chipeta's capital incurred, funded by contributions from the noncontrolling interest owners for all periods presented. Capital incurred for the years ended December 31, 2013 and 2012, included $10.6 million and $6.8 million, respectively, of capitalized interest. Capital incurred for the years ended December 31, 2013, 2012 and 2011, included $8.8 million, $160.9 million and $45.7 million, respectively, of pre-acquisition capital incurred for the Non-Operated Marcellus Interest, the MGR assets, and the Bison assets.

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. Acquisitions during 2011 included the Bison facility and the Platte Valley system. 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 $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 $114.2 million related to the construction of the Lancaster plants and a $91.7 million increase in expenditures at the Wattenberg and Hilight systems and the

Anadarko-Operated Marcellus Interest. These increases were partially offset by a $191.2 million decrease at Chipeta, the Non-Operated Marcellus Interest, the Brasada facility and the Platte Valley system. Maintenance capital expenditures decreased by $7.3 million, primarily as a result of decreased expenditures of $7.5 million at the Wattenberg, Hilight, Haley, and Platte Valley systems, the Red Desert complex and the Non-Operated Marcellus Interest, partially offset by a $1.7 million increase at the Anadarko-Operated Marcellus Interest.

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Capital expenditures, excluding acquisitions, increased by $488.4 million for the year ended December 31, 2012. Expansion capital expenditures increased by $479.6 million for the year ended December 31, 2012, primarily due to an increase of $189.3 million related to the construction of the Brasada gas processing facility and Lancaster plant, $167.3 million in expenditures for the Non-Operated Marcellus Interest, $127.3 million in expenditures at our Wattenberg, Chipeta, and Platte Valley systems and at the Red Desert complex, and $6.8 million of capitalized interest expense. These increases were partially offset by a $7.2 million decrease related to the Bison assets due to the continued startup costs incurred in early 2011, and a $1.2 million decrease at the Granger complex. Maintenance capital expenditures increased by $8.8 million, primarily as a result of increased expenditures of $10.0 million due to higher well connects at the Non-Operated Marcellus Interest, the Platte Valley and Haley systems, and the Red Desert complex, partially offset by $2.3 million in 2011 improvements at the Hugoton system.
We estimate our total capital expenditures for the year ended December 31, 2014, including our 75% share of Chipeta's capital expenditures and excluding acquisitions, to be $614 million to $664 million and our maintenance capital expenditures to be 9% to 11% of total capital expenditures. Expected 2014 projects include the construction of a second train at our Lancaster plant and continued well connections in the Denver-Julesburg basin and the Marcellus shale. Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us, which are dependent, in part, on the drilling activities of Anadarko and third-party producers. We expect to fund future capital expenditures from cash flows generated from our operations, interest income from our note receivable from Anadarko, borrowings under our RCF, the issuance of additional partnership units or debt offerings.

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	2013	2012	2011
Net cash provided by (used in):			
Operating activities	$415,721	$338,026	$312,838
Investing activities	(1,416,066)	(1,249,942)	(479,722)
Financing activities	681,092	1,105,338	366,369
Net increase (decrease) in cash and cash equivalents	$(319,253)	$193,422	$199,485

Operating Activities. Net cash provided by operating activities during the year ended December 31, 2013, was $415.7 million, compared to $338.0 million for the year ended December 31, 2012. Operating cash flows increased primarily due to the impact of changes in working capital items, in addition to higher sales volumes and higher average natural gas prices.
Net cash provided by operating activities during the year ended December 31, 2012, was $338.0 million, compared to $312.8 million for the year ended December 31, 2011. Operating cash flows increased primarily due to the impact of changes in working capital items, in addition to higher sales volumes and increased average commodity prices pursuant to commodity price swap agreements and the addition of the Platte Valley assets in March 2011. The impact of changes in working capital items was primarily due to accruals of expected future operating cash receipts and payments.
Refer to Operating Results within this Item 7 for a discussion of our results of operations as compared to the prior periods.

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

- $465.5 million of cash paid for the acquisition of the Non-Operated Marcellus Interest;

- $646.5 million of capital expenditures, net of $0.6 million of contributions in aid of construction costs from affiliates;

- $134.6 million of cash paid for the acquisition of the Anadarko-Operated Marcellus Interest;

- $78.1 million of cash paid for the acquisition of the Mont Belvieu JV;

- $37.3 million of capital contributions to the Mont Belvieu JV to fund our share of construction costs for the fractionation facilities completed in the fourth quarter of 2013;
- $27.5 million of cash paid for the acquisition of OTTCO;
- $19.1 million of cash paid related to a White Cliffs expansion project anticipated to be completed in the first half of 2014; and
- $11.2 million of cash paid for equipment purchases from Anadarko.

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

- $458.6 million of cash paid for the acquisition of the MGR assets;
- $638.1 million of capital expenditures;
- $128.3 million of cash paid for the additional Chipeta interest; and
- $24.7 million of cash paid for equipment purchases from Anadarko.

Net cash used in investing activities for the year ended December 31, 2011, included the following:

- $302.0 million of cash paid for the acquisition of the Platte Valley system;
- $149.7 million of capital expenditures;
- $25.0 million of cash paid for the acquisition of the Bison facility; and
- $3.8 million for equipment purchases from Anadarko.

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

- $273.7 million of net proceeds from our December 2013 equity offering, including net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest, $215.0 million of which was used to repay a portion of our outstanding borrowings under our RCF;
- $424.7 million of net proceeds from our May 2013 equity offering, including net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest, $245.0 million of which was used to repay a portion of our outstanding borrowings under our RCF;
- $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, including $250.0 million of borrowings to fund the acquisition of the Non-Operated Marcellus Interest;
- $133.5 million of borrowings to fund the acquisition of the Anadarko-Operated Marcellus Interest;
- $299.0 million of borrowings to fund capital expenditures;

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- $27.5 million of borrowings to fund the acquisition of OTTCO;

- $41.8 million of net proceeds from activity under our Continuous Offering Program (as defined and discussed in Registered Securities within this Item 7), including net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest; and

- $0.5 million of net proceeds from the issuance of general partner units to our general partner to maintain its 2.0% general partner interest after common units were issued in conjunction with the acquisition of the Non-Operated Marcellus Interest.

Net contributions from Anadarko attributable to intercompany balances were $4.5 million during the year ended December 31, 2013, representing intercompany transactions attributable to 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 offering 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 WES 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 $171.1 million during the year ended December 31, 2012, representing intercompany transactions attributable to the acquisition of the Non-Operated Marcellus Interest, the compensation expense allocated to us since the inception of the Incentive Plan and the settlement of intercompany transactions attributable to the MGR assets.

Net cash provided by financing activities for the year ended December 31, 2011, included the following:

- $493.9 million of net proceeds from our 2021 Notes offering in May 2011, after underwriting and original issue discounts and offering costs;

- $303.0 million of borrowings to fund the acquisition of the Platte Valley system;

- $250.0 million repayment of the Wattenberg term loan (described below) using borrowings from our RCF;

- $202.8 million of net proceeds from our September 2011 equity offering; and

- $132.6 million of net proceeds from our March 2011 equity offering.

Proceeds from our 2021 Notes offering and our March 2011 equity offering were used to repay $619.0 million of borrowings outstanding under our RCF.
Net distributions to Anadarko attributable to pre-acquisition intercompany balances were $36.0 million during 2011, attributable to the Non-Operated Marcellus Interest and the net non-cash settlement of intercompany transactions attributable to the MGR assets and the Bison facility.

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For the years ended December 31, 2013, 2012 and 2011, we paid $299.1 million, $197.9 million and $140.1 million, respectively, of cash distributions to our unitholders. Contributions from noncontrolling interest owners of Chipeta totaled $2.2 million, $29.1 million and $33.6 million during the years ended December 31, 2013, 2012 and 2011, respectively, primarily for expansion of the cryogenic units and plant construction. Distributions to noncontrolling interest owners of Chipeta totaled $13.1 million, $17.3 million and $17.5 million for the years ended December 31, 2013, 2012 and 2011, 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. As of December 31, 2013, the carrying value of our outstanding debt consisted of $249.7 million of the 2018 Notes, $673.3 million of the 2022 Notes and $495.2 million of the 2021 Notes. See Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Senior Notes. In August 2013, we completed the offering of $250.0 million aggregate principal amount of 2.600% Senior Notes due 2018 at a price to the public of 99.879% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2018 Notes is 2.806%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $1.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under our RCF.
The 2018 Notes mature on August 15, 2018, unless earlier redeemed. The Partnership may redeem the 2018 Notes in whole or in part, at any time before July 15, 2018, at a redemption price equal to the greater of (i) 100% of the principal amount of the 2018 Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on such 2018 Notes (exclusive of interest accrued to the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in the indenture governing the 2018 Notes) plus 20 basis points, plus, in either case, accrued and unpaid interest to such redemption date, if any, on the principal amount being redeemed. On or after July 15, 2018, the 2018 Notes may be redeemed, at any time in whole, or from time to time in part, at a price equal to 100% of the principal amount of the 2018 Notes to be redeemed, plus accrued interest on the 2018 Notes to be redeemed to the date of redemption.
In June 2012, we completed the offering of $520.0 million aggregate principal amount of the 2022 Notes at a price to the public of 99.194% of the face amount. In October 2012, we issued an additional $150.0 million in aggregate principal amount of the 2022 Notes at a price to the public of 105.178% of the face amount. The additional notes were issued under the same indenture as, and as a single class of securities with, the June 2012 issuance. Including the effects of the issuance discount for the June 2012 offering, the issuance premium for the October 2012 offering, and underwriting discounts, the effective interest rate of the 2022 Notes is 4.040%. Interest is paid semi-annually on January 1 and July 1 of each year. Proceeds (net of underwriting discounts of $4.4 million and debt issuance costs) were used to repay all amounts then outstanding under our RCF and the $175.0 million note payable to Anadarko (see below), with the remaining net proceeds used for general partnership purposes.
The 2022 Notes mature on July 1, 2022, unless earlier redeemed. We may redeem the 2022 Notes in whole or in part, at any time before April 1, 2022, at a redemption price equal to the greater of (i) 100% of the principal amount of the 2022 Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on such 2022 Notes (exclusive of interest accrued to the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in the indenture governing the 2022 Notes) plus 37.5 basis points, plus, in either case, accrued and unpaid interest, if any, on the principal amount being redeemed to such redemption date. On or after April 1, 2022, the 2022 Notes may be redeemed, at any time in whole, or from time to time in part, at a price equal to 100% of the principal amount of the 2022 Notes to be redeemed, plus accrued interest on the 2022 Notes to be redeemed to the date of redemption.

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In May 2011, we completed the offering of $500.0 million aggregate principal amount of the 2021 Notes at a price to the public of 98.778% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate is 5.648%. Interest on the 2021 Notes is paid semi-annually on June 1 and December 1 of each year. Proceeds from the offering of the 2021 Notes (net of the underwriting discount of $3.3 million and debt issuance costs) were used to repay the then-outstanding balance on the Partnership's RCF, with the remainder used for general partnership purposes. Upon issuance, the 2021 Notes were fully and unconditionally guaranteed on a senior unsecured basis by each of our wholly owned subsidiaries (the "Subsidiary Guarantors"). The Subsidiary Guarantors' guarantees were immediately released on June 13, 2012, upon the Subsidiary Guarantors becoming released from their obligations under our RCF, as discussed below.

The 2021 Notes mature on June 1, 2021, unless earlier redeemed. We may redeem the 2021 Notes in whole or in part, at any time before March 1, 2021, at a redemption price equal to the greater of (i) 100% of the principal amount of the 2021 Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on such 2021 Notes (exclusive of interest accrued to the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in the indenture governing the 2021 Notes) plus 40 basis points, plus, in either case, accrued and unpaid interest, if any, on the principal amount being redeemed to such redemption date. On or after March 1, 2021, the 2021 Notes may be redeemed, at any time in whole, or from time to time in part, at a price equal to 100% of the principal amount of the 2021 Notes to be redeemed, plus accrued interest on the 2021 Notes to be redeemed to the date of redemption.

The indentures governing the 2021 Notes, 2022 Notes, and 2018 Notes contain customary events of default including, among others, (i) default for 30 days in the payment of interest when due; (ii) default in payment, when due, of principal of or premium, if any, at maturity, upon redemption or otherwise; and (iii) certain events of bankruptcy or insolvency. The indentures also contain covenants that limit, among other things, our ability, as well as that of certain of our subsidiaries, to (i) create liens on our principal properties; (ii) engage in sale and leaseback transactions; and (iii) merge or consolidate with another entity or sell, lease or transfer substantially all of our properties or assets to another entity. At December 31, 2013, we were in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, and the 2018 Notes.

Note payable to Anadarko. In 2008, we 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. As of December 31, 2013, we had no outstanding borrowings and $12.8 million in outstanding letters of credit issued under our $800.0 million RCF. The RCF matures in March 2016 and bears interest at London Interbank Offered Rate ("LIBOR") plus applicable margins currently ranging from 1.30% to 1.90%, 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 0.30% to 0.90%. The interest rate was 1.67% and 1.71% at December 31, 2013 and 2012, respectively. We are required to pay a quarterly facility fee currently ranging from 0.20% to 0.35% of the commitment amount (whether used or unused), based upon our senior unsecured debt rating. The facility fee rate was 0.25% at December 31, 2013 and 2012. At December 31, 2013, we were in compliance with all covenants under the RCF. See Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

On June 13, 2012, following the receipt of a second investment grade rating as defined in the RCF, the guarantees provided by our wholly owned subsidiaries were released, and we are no longer subject to certain of the restrictive covenants associated with the RCF, including the maintenance of an interest coverage ratio and adherence to covenants that limit, among other things, our ability, and that of certain of our subsidiaries, to dispose of assets and make certain investments or payments. 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, 2013, we were in compliance with all remaining covenants under the RCF.

The 2021 Notes, the 2022 Notes, the 2018 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, the 2021 Notes, and/or the RCF. See Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

In connection with the acquisition of the Non-Operated Marcellus Interest in March 2013, our general partner and another wholly owned subsidiary of Anadarko entered into an indemnification agreement (the “2013 Indemnification Agreement”) whereby such subsidiary 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 or the Anadarko-Operated Marcellus Interest. The 2013 Indemnification Agreement applies to the 2018 Notes. Our general partner and WGRI also amended and restated the existing indemnity agreement between them to reduce the amount for which WGRI would indemnify our general partner by an amount equal to any amounts payable to our general partner under the 2013 Indemnification Agreement. See Note 12—Subsequent Events in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Wattenberg term loan. In connection with the Wattenberg acquisition, in August 2010 we borrowed $250.0 million under a three-year term loan from a group of banks (“Wattenberg term loan”). The Wattenberg term loan incurred interest at LIBOR plus a margin ranging from 2.50% to 3.50% depending on our consolidated leverage ratio as defined in the Wattenberg term loan agreement. We repaid the Wattenberg term loan in March 2011 using borrowings from our RCF and recognized $1.3 million of accelerated amortization expense related to its early repayment.

Registered securities. We may issue an indeterminate amount of common units and various debt securities under our effective shelf registration statements on file with the SEC.

In August 2012, we filed a registration statement with the SEC authorizing the issuance of up to an aggregate of $125.0 million of common units, in amounts, at prices and on terms to be determined by market conditions and other factors at the time of our offerings (the “Continuous Offering Program”). 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 our Continuous Offering Program.

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.

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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 initial public offering. 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 commodity price risk and are subject to performance risk thereunder.
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, 2013. 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 2014.

	Obligations by Period						
thousands	2014	2015	2016	2017	2018	Thereafter	Total
Long-term debt							
Principal	—	—	—	—	250,000	1,170,000	1,420,000
Interest	59,652	59,634	59,614	59,595	56,324	160,275	455,094
Asset retirement obligations	1,966	1,755	127	—	—	74,187	78,035
Capital expenditures	47,112	—	—	—	—	—	47,112
Credit facility fees	2,000	2,000	460	—	—	—	4,460
Environmental obligations	932	532	532	135	135	579	2,845
Operating leases	309	245	233	157	34	—	978
Total	$111,971	$64,166	$60,966	$59,887	$306,493	$1,405,041	$2,008,524

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

Asset retirement obligations. When assets are acquired or constructed, the initial estimated asset retirement obligation is recognized in an amount equal to the net present value of the settlement obligation, with an associated increase in properties and equipment. Revisions to estimated asset retirement obligations can result from revisions to estimated inflation rates and discount rates, changes in retirement costs and the estimated timing of settlement. For additional information, see Note 9—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 11—Commitments and Contingencies in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

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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 11—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 11—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 11—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 properties 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 $18.7 million, which would result in a corresponding reduction in our operating income.

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.

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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 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.

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.

During 2011, we recognized a $7.3 million impairment related to certain equipment and materials. The costs of the equipment and materials, previously capitalized as assets under construction and related to a Red Desert complex expansion project, were deemed no longer recoverable as the expansion project was indefinitely postponed by Anadarko management. Subsequent to the project evaluation and impairment, the remaining fair value of the equipment and materials was reclassified from within property, plant and equipment to other assets on the consolidated balance sheet and was $10.6 million as of December 31, 2011. Also during 2011, following an evaluation of future cash flows, an impairment of $3.0 million was recognized for a transportation pipeline that was impaired to its estimated fair value using Level 3 fair-value inputs.

Impairments of goodwill. Goodwill represents the allocated portion of Anadarko's midstream goodwill attributed to the assets we have acquired from Anadarko. The carrying value of Anadarko's midstream goodwill represents the excess of the purchase price of an entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, our goodwill balance does not reflect, and in some cases is significantly higher than, the difference between the consideration paid by us for acquisitions from Anadarko compared to the fair value of the net assets acquired.

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, 2013, was $100.5 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. 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, 2013. However, fair-value estimates of our reporting units may be required for goodwill impairment testing in the future, and if the carrying amount of a reporting unit exceeds its fair value, goodwill is written down to the implied fair value through a charge to operating expense based on a hypothetical purchase price allocation.

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Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test, when necessary. Management uses information available to make these fair value estimates, including market multiples of earnings before interest, taxes, depreciation, and amortization ("EBITDA"). Specifically, our management estimates fair value by applying an estimated multiple to projected 2014 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, 2013 and 2012, 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 amortized on a straight-line basis over 50 years, and (ii) interconnect agreements at Chipeta entered into in November 2012, amortized on a straight-line basis over 10 years.
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 are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, the impairment loss is measured as the excess of the asset's carrying amount over its estimated fair value, such that the asset's carrying amount is adjusted to its estimated fair value with an offsetting charge to impairment expense. No intangible asset impairment has been recognized in connection with these assets.

Fair value. Management estimates fair value in performing impairment tests for long-lived assets and goodwill as well as for the initial measurement of asset retirement obligations and the initial recognition of environmental obligations assumed in third-party acquisitions. When our management is required to measure fair value and there is not a market-observable price for the asset or liability or a market-observable price for a similar asset or liability, management utilizes the cost, income, or market multiples valuation approach depending on the quality of information available to support management's assumptions. The 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. The information pertaining to operating leases required for this item is provided under Note 11—Commitments and Contingencies included in the

Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

RECENT ACCOUNTING DEVELOPMENTS

None.

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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 and NGLs. Under percent-of-proceeds agreements, we receive a specified percentage of the net proceeds from the sale of natural gas and NGLs. Under keep-whole agreements, we keep 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, we compensate the producer for this amount of gas by supplying additional gas or by paying an agreed-upon value for the gas utilized. To mitigate our exposure to 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. For additional information on the commodity price swap agreements, see 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 New York Mercantile Exchange, or 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 also 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, 2013, were low compared to historic rates. As of December 31, 2013, we had no outstanding borrowings under our RCF (which bears interest at a rate based on LIBOR or, at our option, an alternative base rate). If interest rates rise, our future financing costs could increase. A 10% change in LIBOR would have resulted in no change in net income or in the fair value of the borrowings under the RCF at December 31, 2013.

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, 2013. This assessment was based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we believe that as of December 31, 2013 the Partnership's internal control over financial reporting is effective based on those criteria.

KPMG LLP has issued an attestation report on the Partnership's internal control over financial reporting as of December 31, 2013.

/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 28, 2014

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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, 2013, based on criteria established in Internal Control — Integrated Framework (1992) 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, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.
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, 2013 and 2012, 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, 2013, and our report dated February 28, 2014 expressed an unqualified opinion on those consolidated financial statements.
/s/ KPMG LLP
Houston, Texas
February 28, 2014

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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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2014 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.
/s/ KPMG LLP
Houston, Texas
February 28, 2014

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WESTERN GAS PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
thousands except per-unit amounts	2013	2012	2011
Revenues – affiliates			
Gathering, processing and transportation of natural gas and natural gas liquids	$306,810	$249,997	$227,535
Natural gas, natural gas liquids and condensate sales	496,848	436,423	417,547
Equity income and other, net	25,600	17,717	13,598
Total revenues – affiliates	829,258	704,137	658,680
Revenues – third parties			
Gathering, processing and transportation of natural gas and natural gas liquids	175,732	132,333	119,934
Natural gas, natural gas liquids and condensate sales	44,396	71,916	84,836
Other, net	4,109	2,201	5,955
Total revenues – third parties	224,237	206,450	210,725
Total revenues	1,053,495	910,587	869,405
Operating expenses			
Cost of product [(1)]	364,285	336,079	327,371
Operation and maintenance [(1)]	168,657	140,106	126,464
General and administrative [(1)]	29,751	99,212	40,564
Property and other taxes	23,244	19,688	16,579
Depreciation, amortization and impairments	145,916	120,608	113,133
Total operating expenses	731,853	715,693	624,111
Operating income	321,642	194,894	245,294
Interest income, net – affiliates	16,900	16,900	24,106
Interest expense [(2)]	(51,797)	(42,060)	(30,345)
Other income (expense), net	1,837	292	(44)
Income before income taxes	288,582	170,026	239,011
Income tax expense	2,630	20,715	32,150
Net income	285,952	149,311	206,861
Net income attributable to noncontrolling interests	10,816	14,890	14,103
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Limited partners' interest in net income:			
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Pre-acquisition net (income) loss allocated to Anadarko	(4,637)	(27,435)	(52,599)
General partner interest in net (income) loss [(3)]	(69,633)	(28,089)	(8,599)
Limited partners' interest in net income[(3)]	$200,866	$78,897	$131,560
Net income per common unit – basic and diluted	$1.83	$0.84	$1.64
Net income per subordinated unit – basic and diluted[(4)]	$—	$—	$1.28

(1) Cost of product includes product purchases from Anadarko (as defined in Note 1) of $129.0 million, $145.3 million and $83.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. Operation and maintenance includes charges from Anadarko of $56.4 million, $51.2 million and $51.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. General and administrative includes charges from Anadarko of $23.4 million, $92.8 million and $33.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. See Note 5.

(2)

Includes affiliate (as defined in Note 1) interest expense of zero, $2.8 million and $4.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. See Note 10.

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

(4) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. See Note 4.

See accompanying Notes to Consolidated Financial Statements.

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WESTERN GAS PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

thousands except number of units	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$100,728	$419,981
Accounts receivable, net [(1)]	84,060	50,233
Other current assets [(2)]	10,022	6,998
Total current assets	194,810	477,212
Note receivable – Anadarko	260,000	260,000
Property, plant and equipment		
Cost	4,239,100	3,432,392
Less accumulated depreciation	855,845	714,436
Net property, plant and equipment	3,383,255	2,717,956
Goodwill	105,336	105,336
Other intangible assets	53,606	55,490
Equity investments	243,619	106,130
Other assets	27,401	27,798
Total assets	$4,268,027	$3,749,922
LIABILITIES, EQUITY AND PARTNERS' CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [(3)]	$39,589	$25,154
Accrued ad valorem taxes	13,860	11,949
Income taxes payable	—	552
Accrued liabilities [(4)]	137,011	147,651
Total current liabilities	190,460	185,306
Long-term debt	1,418,169	1,168,278
Deferred income taxes	309	47,153
Asset retirement obligations and other	79,145	68,749
Total long-term liabilities	1,497,623	1,284,180
Total liabilities	1,688,083	1,469,486
Equity and partners' capital		
Common units (117,322,812 and 104,660,553 units issued and outstanding at December 31, 2013 and 2012, respectively)	2,431,193	1,957,066
General partner units (2,394,345 and 2,135,930 units issued and outstanding at December 31, 2013 and 2012, respectively)	78,157	52,752
Net investment by Anadarko	—	199,960
Total partners' capital	2,509,350	2,209,778
Noncontrolling interests	70,594	70,658
Total equity and partners' capital	2,579,944	2,280,436
Total liabilities, equity and partners' capital	$4,268,027	$3,749,922

(1) Accounts receivable, net includes amounts receivable from affiliates (as defined in Note 1) of $47.9 million and $19.1 million as of December 31, 2013 and 2012, respectively.

(2) Other current assets includes natural gas imbalance receivables from affiliates of $0.1 million and $0.4 million as of December 31, 2013 and 2012, respectively.

(3) Accounts and natural gas imbalance payables includes amounts payable to affiliates of $2.3 million and $2.5 million as of December 31, 2013 and 2012, respectively.

(4) Accrued liabilities include amounts payable to affiliates of $0.1 million as of December 31, 2013 and 2012.

See accompanying Notes to Consolidated Financial Statements.

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

thousands	Partners' Capital					
	Net Investment by Anadarko	Common Units	Subordinated Units	General Partner Units	Noncontrolling Interests	Total
Balance at December 31, 2010	$408,243	$810,717	$282,384	$21,505	$ 90,462	$1,613,311
Net income	52,599	110,542	21,018	8,599	14,103	206,861
Conversion of subordinated units to common units [1]	—	272,222	(272,222)	—	—	—
Issuance of common and general partner units, net of offering expenses	—	328,345	—	6,972	—	335,317
Contributions from noncontrolling interest owners	—	—	—	—	33,637	33,637
Distributions to noncontrolling interest owners	—	—	—	—	(17,478)	(17,478)
Distributions to unitholders	—	(102,091)	(31,180)	(6,847)	—	(140,118)
Acquisition from affiliates	(92,666)	66,313	—	1,353	—	(25,000)
Contributions of equity-based compensation from Anadarko [2]	—	9,472	—	194	—	9,666
Net pre-acquisition contributions from (distributions to) Anadarko	(33,785)	—	—	—	—	(33,785)
Elimination of net deferred tax liabilities	22,072	—	—	—	—	22,072
Other	—	(267)	—	(47)	—	(314)
Balance at December 31, 2011	$356,463	$1,495,253	$—	$31,729	$ 120,724	$2,004,169
Net income	27,435	78,897	—	28,089	14,890	149,311
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 [3]	—	(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	192,259	(106,597)	—	—	—	85,662
Net distributions of other assets to Anadarko	—	(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	$199,960	$1,957,066	$—	$52,752	$ 70,658	$2,280,436

Net income	4,637	200,866	—	69,633	10,816	285,952
Issuance of common and general partner units, net of offering expenses	—	724,811	—	15,775	—	740,586
Contributions from noncontrolling interest owners	—	—	—	—	2,247	2,247
Distributions to noncontrolling interest owners	—	—	—	—	(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	4,508	—	—	—	—	4,508
Net distributions of other assets to Anadarko	—	(5,738)	—	(117)		(5,855)
Elimination of net deferred tax liabilities	46,530	—	—	—	—	46,530
Other	—	345	—	—	—	345
Balance at December 31, 2013	$—	$2,431,193	$—	$78,157	$ 70,594	$2,579,944

(1) All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. See Note 4.

(2) Associated with the Anadarko Incentive Plans for the years ended December 31, 2011 and 2013, associated with the Anadarko Incentive Plans and the Incentive Plan for the year ended December 31, 2012, as defined and described in Note 1 and Note 5.

(3) 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.

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	2013	2012	2011
Cash flows from operating activities			
Net income	$285,952	$149,311	$206,861
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairments	145,916	120,608	113,133
Non-cash equity-based compensation expense	3,521	3,717	3,490
Deferred income taxes	(314)	30,113	16,580
Debt-related amortization and other items, net	2,449	2,319	3,110
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	(34,019)	22,916	(44,725)
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	21,952	5,045	30,884
Change in other items, net	(9,736)	3,997	(16,495)
Net cash provided by operating activities	415,721	338,026	312,838
Cash flows from investing activities			
Capital expenditures	(646,471)	(638,121)	(149,717)
Contributions in aid of construction costs from affiliates	617	—	—
Acquisitions from affiliates	(476,711)	(611,719)	(28,837)
Acquisitions from third parties	(240,274)	—	(301,957)
Investments in equity affiliates	(51,974)	(862)	(93)
Proceeds from the sale of assets to affiliates	85	760	382
Other	(1,338)	—	500
Net cash used in investing activities	(1,416,066)	(1,249,942)	(479,722)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	957,503	1,041,648	1,055,939
Repayments of debt	(710,000)	(549,000)	(869,000)
Increase (decrease) in outstanding checks	(1,763)	1,800	4,039
Proceeds from the issuance of common and general partner units, net of offering expenses	740,825	625,877	335,317
Distributions to unitholders	(299,101)	(197,850)	(140,118)
Contributions from noncontrolling interest owners	2,247	29,108	33,637
Distributions to noncontrolling interest owners	(13,127)	(17,303)	(17,478)
Net contributions from (distributions to) Anadarko	4,508	171,058	(35,967)
Net cash provided by financing activities	681,092	1,105,338	366,369
Net increase (decrease) in cash and cash equivalents	(319,253)	193,422	199,485
Cash and cash equivalents at beginning of period	419,981	226,559	27,074
Cash and cash equivalents at end of period	$100,728	$419,981	$226,559
Supplemental disclosures			
Net distributions to (contributions from) Anadarko of other assets	$5,855	$15,296	$(29)
Interest paid, net of capitalized interest	$47,098	$28,042	$25,828
Taxes paid	$552	$495	$190

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 consolidated subsidiaries, excluding the Partnership and the general partner, and “affiliates” refers to wholly owned and partially owned 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”), and Enterprise EF78 LLC (the “Mont Belvieu JV”). See Note 2. “Equity investment throughput” refers to the Partnership’s 14.81% share of Fort Union and 22% share of Rendezvous gross volumes.
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 third-party producers and customers. As of December 31, 2013, the Partnership’s assets, exclusive of interests in Fort Union, White Cliffs, Rendezvous and the Mont Belvieu JV accounted for under the equity method, consisted of the following:

	Owned and Operated	Operated Interests	Non-Operated Interests
Natural gas gathering systems	13	1	5
Natural gas treating facilities	8	—	—
Natural gas processing facilities	8	3	—
NGL pipelines	3	—	—
Natural gas pipelines	3	—	—

These assets are located in the Rocky Mountains (Colorado, Utah and Wyoming), the Mid-Continent (Kansas and Oklahoma), north-central Pennsylvania, and East, South and West Texas. The Partnership was also constructing the Lancaster processing plant in Northeast Colorado at the end of the fourth quarter of 2013.

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 2.0% 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 WES.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 and Anadarko-Operated Marcellus Interest (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. References to the "Partnership assets" refer collectively to the assets owned by the Partnership as of December 31, 2013. Because Anadarko controls the Partnership through its ownership and control of WGP, which owns the Partnership's general partner, each of the Partnership's acquisitions of assets from Anadarko has been considered a transfer of net assets between entities under common control. As such, the Partnership assets acquired from Anadarko were initially recorded at Anadarko's historic carrying value, which did not correlate to the total acquisition price paid by the Partnership. Further, after an acquisition of assets from Anadarko, the Partnership may be required to recast its financial statements to include the activities of such assets as of the date of common control. See Note 2.

For those periods requiring recast, the consolidated financial statements for periods prior to the Partnership's acquisition of the Partnership assets from Anadarko have been prepared from Anadarko's historical cost-basis accounts and may not necessarily be indicative of the actual results of operations that would have occurred if the Partnership had owned the assets during the periods reported. Net income attributable to the Partnership assets acquired from Anadarko for periods prior to the Partnership's acquisition of such assets is not allocated to the limited partners for purposes of calculating net income per common unit or subordinated unit.

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.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 10.
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.

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, 2013, the third-party accounts receivable balance was net of the associated bad-debt reserve of $13,000. As of December 31, 2012, there was no reserve for bad debts.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, 2013, natural gas imbalance receivables and payables were $3.6 million and $2.5 million, respectively. As of December 31, 2012, natural gas imbalance receivables and payables were $1.7 million and $3.1 million, respectively. Changes in natural gas imbalances are reported in equity income and other, net 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.

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, 2013, 2012 and 2011.

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 represents the allocated portion of Anadarko’s midstream goodwill attributed to the assets the Partnership has 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 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, 2013 and 2012, include goodwill of $105.3 million, the impairment of which (if applicable) is not deductible for tax purposes.

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. Estimating the fair value of the Partnership’s reporting units was not necessary based on the qualitative evaluation as of October 1, 2013, and no goodwill impairment has been recognized in these consolidated financial statements.

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 amortized on a straight-line basis over 50 years, and (ii) interconnect agreements at Chipeta entered into in November 2012, amortized on a straight-line basis over 10 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 within this 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. As of December 31, 2013, the carrying value of the Partnership’s intangible assets was $53.6 million, net of $3.4 million of accumulated amortization. The Partnership estimates that it will record $1.4 million of intangible asset amortization for each of the next five years. As of December 31, 2012, the carrying value of the Partnership’s intangible assets was $55.5 million, net of $2.0 million of accumulated amortization.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Equity-method investments. The following table presents the activity in the Partnership's investments in equity of Fort Union, White Cliffs, Rendezvous and Mont Belvieu JV:

	Equity Investments			
thousands	Fort Union (1)	White Cliffs (2)	Rendezvous (3)	Mont Belvieu JV (4)
Balance at December 31, 2011	$22,268	$17,710	$69,839	$—
Investment earnings, net of amortization	6,383	7,871	1,857	—
Contributions	—	862	—	—
Distributions	(5,198)	(8,876)	(6,586)	—
Balance at December 31, 2012	$23,453	$17,567	$65,110	$—
Initial investment	—	—	—	78,129
Investment earnings, net of amortization	6,273	9,681	2,088	5,690
Contributions	16	19,087	—	38,661
Distributions	(4,570)	(9,266)	(4,029)	—
Distributions in excess of cumulative earnings	—	(2,030)	(2,241)	—
Balance at December 31, 2013	$25,172	$35,039	$60,928	$122,480

(1) The Partnership has a 14.81% interest in Fort Union, a joint venture which 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 which 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.

The investment balance at December 31, 2013, includes $2.5 million and $44.0 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, 2013, is $9.3 million less than the Partnership's underlying equity in White Cliffs' net assets as of December 31, 2013, 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 over the remaining estimated useful life of the White Cliffs pipeline.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Management evaluates its equity-method 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-method 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 method investments (amounts represents 100% of investee financial information):

	Year Ended December 31,		
thousands	2013	2012	2011
Consolidated Statements of Income			
Revenues	$256,632	$199,764	$153,131
Operating income	176,370	135,577	90,549
Net income	175,060	134,066	88,521

	December 31,	
thousands	2013	2012
Consolidated Balance Sheets		
Current assets	$171,457	$44,474
Property, plant and equipment, net	1,174,034	611,441
Other assets	38,258	45,100
Total assets	$1,383,749	$701,015
Current liabilities	86,606	20,174
Non-current liabilities	32,704	50,759
Equity	1,264,439	630,082
Total liabilities and equity	$1,383,749	$701,015

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 9.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 11.

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.

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 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.

WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 2,139,027 units remained available for future issuance as of December 31, 2013. 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.

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 year ended December 31, 2013, (ii) the Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated (the "Incentive Plan") for the years ended December 31, 2012 and 2011, 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, 2013 or 2012.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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, general partner units and IDRs of the general partner. 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.
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 subordinated unitholders, in accordance with their respective 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 subordinated unitholders by applying the provisions of the partnership agreement that govern actual cash distributions as if all earnings for the period had been distributed. Specifically, net income equal to the amount of available cash (as defined by the partnership agreement) is allocated to the general partner, common unitholders and subordinated unitholders 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, common unitholders and subordinated unitholders in accordance with their respective ownership percentages during each period. See Note 4.

Other assets. For the years ended December 31, 2013 and 2012, other current assets on the consolidated balance sheets includes $0.4 million for a receivable recognized in conjunction with the capital lease component of a processing agreement assumed in connection with the acquisition of Mountain Gas Resources, LLC ("MGR"). See Note 2. The agreement, in which WES is the lessor, extends through December 2014. Other assets includes $4.6 million related to the unguaranteed residual value of the processing plant included in the processing agreement, based on a measurement of fair value estimated when the plant was acquired by Anadarko in 2006. Interest income related to the capital lease is recorded to other income (expense), net on the consolidated statements of income.

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.

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. See Note 12.

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2. ACQUISITIONS (CONTINUED)

The following table presents the acquisitions completed by the Partnership during the years ended December 31, 2011, 2012 and 2013, 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	GP Units Issued
Platte Valley (1)	02/28/2011	100	%	$303,000	$602	—	—
Bison (2)	07/08/2011	100	%	—	25,000	2,950,284	60,210
MGR (3)	01/13/2012	100	%	299,000	159,587	632,783	12,914
Chipeta (4)	08/01/2012	24	%	—	128,250	151,235	3,086
Non-Operated Marcellus Interest (5)	03/01/2013	33.75	%	250,000	215,500	449,129	—
Anadarko-Operated Marcellus Interest (6)	03/08/2013	33.75	%	133,500	—	—	—
Mont Belvieu JV (7)	06/05/2013	25	%	—	78,129	—	—
OTTCO (8)	09/03/2013	100	%	27,500	—	—	—

(1) The Partnership acquired (i) a natural gas gathering system and related compression and other ancillary equipment and (ii) cryogenic gas processing facilities from a third party. These assets are located in the Denver-Julesburg Basin. The acquisition is referred to as the “Platte Valley acquisition.”

(2) The Bison gas treating facility acquired from Anadarko is located in the Powder River Basin in northeastern Wyoming and includes (i) three amine treating units, (ii) compressor units, and (iii) generators. These assets are referred to collectively as the “Bison assets.” The Bison assets are the only treating and delivery point into the third-party-owned Bison pipeline. The Bison assets were placed in service in June 2010.

(3) 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.”

(4) 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.

(5) The Partnership acquired Anadarko’s 33.75% interest (non-operated) in the Liberty and Rome gas gathering systems, serving production from the Marcellus shale in north-central Pennsylvania. The interest acquired is referred to as the “Non-Operated Marcellus Interest” and the acquisition as the “Non-Operated Marcellus Interest acquisition.” 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 in order to maintain its 2.0% general partner interest in the Partnership.

(6) The Partnership acquired a 33.75% interest in each of the Larry’s Creek, Seely and Warrensville gas gathering systems, which are operated by Anadarko and serve production from the Marcellus shale in north-central Pennsylvania, from a third party. The interest acquired is referred to as the “Anadarko-Operated Marcellus Interest” and the acquisition as the “Anadarko-Operated Marcellus Interest acquisition.” See Anadarko-Operated Marcellus Interest acquisition below for further information, including the final allocation of the purchase price.

(7)

The Partnership acquired a 25% interest in Enterprise EF78 LLC, 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 and is referred to as the "Mont Belvieu JV" and the acquisition as the "Mont Belvieu JV acquisition." See Mont Belvieu JV acquisition below for further information.

(8) 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.

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2. ACQUISITIONS (CONTINUED)

Anadarko-Operated Marcellus Interest acquisition. The Anadarko-Operated Marcellus Interest acquisition has been accounted for under the acquisition method of accounting. The assets acquired and liabilities assumed in the Anadarko-Operated Marcellus Interest acquisition were recorded in the consolidated balance sheet at their estimated fair values as of the acquisition date. Results of operations attributable to the Anadarko-Operated Marcellus Interest were included in the Partnership's consolidated statements of income beginning on the acquisition date in the first quarter of 2013.

The following is the final allocation of the purchase price, including $1.1 million of post-closing purchase price adjustments, to the assets acquired and liabilities assumed in the Anadarko-Operated Marcellus Interest acquisition as of the acquisition date:

thousands	
Property, plant and equipment	$134,819
Asset retirement obligations	(174)
Total purchase price	$134,645

The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the Anadarko-Operated Marcellus Interest acquisition. The fair values of the interests in the land, right-of-way contracts, and gathering systems were based on the market and income approaches. All fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs.

The following table presents pro forma condensed financial information of the Partnership as if the Anadarko-Operated Marcellus Interest acquisition had occurred on January 1, 2012:

	Year Ended December 31,	
thousands except per-unit amounts	2013	2012
Revenues	$1,054,749	$915,464
Net income	286,100	147,282
Net income attributable to Western Gas Partners, LP	275,284	132,392
Net income per common unit - basic and diluted	$1.82	$0.82

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 Anadarko-Operated Marcellus Interest 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 $14.1 million of revenues and $0.7 million of operating expenses, excluding depreciation, amortization and impairments, attributable to the Anadarko-Operated Marcellus Interest that are included in the Partnership's consolidated statement of income for the year ended December 31, 2013. The pro forma adjustments reflect pre-acquisition results of the Anadarko-Operated Marcellus Interest including (a) estimated revenues and expenses; (b) estimated depreciation and amortization based on the purchase price allocated to property, plant and equipment and estimated useful lives; and (c) interest on the Partnership's borrowings under its revolving credit facility to finance the Anadarko-Operated Marcellus Interest 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 Anadarko-Operated Marcellus Interest acquisition, nor any future acquisition related expenses.

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2. ACQUISITIONS (CONTINUED)

Mont Belvieu JV acquisition. The acquisition purchase price represented the Partnership's 25% share of construction costs incurred by the joint venture partner and 25% of the capitalized interest charged to the financial statements of the Mont Belvieu JV up to the date of acquisition. The allocated capitalized interest is reflected as a component of the equity investment balance recorded upon acquisition. Based on the total estimated net project cost, the construction of the fractionation facilities owned by the Mont Belvieu JV is considered a significant project and satisfies criteria for capitalization of interest. Capitalization of interest subsequent to the acquisition is treated as a basis difference between the cost of the investment and the underlying equity in the net assets of the Mont Belvieu JV. Upon completion of construction in the fourth quarter of 2013, the Partnership began amortizing the capitalized interest recognized subsequent to the Mont Belvieu JV acquisition. This amortization is reflected as an adjustment to equity earnings from the Mont Belvieu JV.

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 unitholders for the periods presented:

thousands except per-unit amounts Quarters Ended	Total Quarterly Distribution per Unit	Total Quarterly Cash Distribution	Date of Distribution
2011			
March 31	$0.390	$33,168	May 2011
June 30	$0.405	$36,063	August 2011
September 30	$0.420	$40,323	November 2011
December 31	$0.440	$43,027	February 2012
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 [1]	$0.600	$92,609	February 2014

(1) On January 20, 2014, the board of directors of the Partnership's general partner declared a cash distribution to the Partnership's unitholders of $0.60 per unit, or $92.6 million in aggregate, including incentive distributions. The cash distribution is payable on February 12, 2014, to unitholders of record at the close of business on January 31, 2014.

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 (such as the Chipeta LLC agreement); 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.

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3. PARTNERSHIP DISTRIBUTIONS (CONTINUED)

General partner interest and incentive distribution rights. The general partner is currently entitled to 2.0% of all quarterly distributions that the Partnership makes prior to its liquidation. The Partnership's general partner is entitled to incentive distributions if the amount the Partnership distributes with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum quarterly distribution	$0.300	98.0%	2.0%
First target distribution	up to $0.345	98.0%	2.0%
Second target distribution	above $0.345 up to $0.375	85.0%	15.0%
Third target distribution	above $0.375 up to $0.450	75.0%	25.0%
Thereafter	above $0.450	50.0%	50.0%

The table above assumes that the Partnership's general partner maintains its 2.0% general partner interest and that the general partner continues to own the IDRs. The maximum distribution sharing percentage of 50.0% includes distributions paid to the general partner on its 2.0% general partner interest and does not include any distributions that the general partner may receive on common units that it owns or may acquire.

4. EQUITY AND PARTNERS' CAPITAL

Equity offerings. The Partnership completed the following public offerings of its common units during 2011, 2012 and 2013:

thousands except unit and per-unit amounts	Common Units Issued (1)	GP Units Issued (2)	Price Per Unit	Underwriting Discount and Other Offering Expenses	Net Proceeds
March 2011 equity offering	3,852,813	78,629	$35.15	$5,621	$132,569
September 2011 equity offering	5,750,000	117,347	35.86	7,655	202,748
June 2012 equity offering	5,000,000	102,041	43.88	7,468	216,409
May 2013 equity offering	7,015,000	143,163	61.18	13,203	424,733
December 2013 equity offering (3)	4,500,000	91,837	61.51	8,716	273,728

(1) Includes the issuance of 302,813 common units, 750,000 common units and 915,000 common units pursuant to the full exercise of the underwriters' over-allotment option granted in connection with the March 2011, September 2011 and May 2013 equity offerings, respectively.

(2) Represents general partner units issued to the general partner in exchange for the general partner's proportionate capital contribution to maintain its 2.0% general partner interest.

(3) Excludes the issuance of 300,000 common units on January 3, 2014, pursuant to the partial exercise of the underwriters' over-allotment option, and the corresponding issuance of 6,122 general partner units to the general partner in exchange for the general partner's proportionate capital contribution to maintain its 2.0% general partner interest. Total net proceeds for the partial exercise of the underwriters' over-allotment option (including the general partner's proportionate capital contribution) were $18.3 million.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

In addition, 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"), during the three months ended December 31, 2013, the Partnership completed trades totaling 642,385 common units at an average price per unit of $60.83, generating gross proceeds of $39.9 million (including the general partner's proportionate capital contribution and before $0.9 million of associated offering expenses). During the year ended December 31, 2013, the Partnership completed trades totaling 685,735 common units at an average price per unit of $60.84, generating gross proceeds of $42.6 million (including the general partner's proportionate capital contribution and before $1.0 million of associated offering expenses).

Common and general partner units. The Partnership's common units are listed on the New York Stock Exchange under the symbol "WES."
The following table summarizes common and general partner units issued during the years ended December 31, 2012 and 2013:

	Common Units	General Partner Units	Total
Balance at December 31, 2011	90,140,999	1,839,613	91,980,612
MGR acquisition	632,783	12,914	645,697
Long-Term Incentive Plan awards	12,570	257	12,827
June 2012 equity offering	5,000,000	102,041	5,102,041
Chipeta acquisition	151,235	3,086	154,321
WGP unit purchase agreement	8,722,966	178,019	8,900,985
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

Holdings of Partnership equity. As of December 31, 2013, WGP held 49,296,205 common units, representing a 41.2% limited partner interest in the Partnership, and, through its ownership of the general partner, WGP indirectly held 2,394,345 general partner units, representing a 2.0% general partner interest in the Partnership, and 100% of the Partnership's IDRs. As of December 31, 2013, Anadarko Marcellus Midstream, L.L.C. ("AMM"), a subsidiary of Anadarko, separately held 449,129 common units, representing a 0.4% limited partner interest in the Partnership. As of December 31, 2013, the public held 67,577,478 common units, representing a 56.4% 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.
Basic and diluted net income per common unit are calculated by dividing the limited partners' interest in net income 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.

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4. EQUITY AND PARTNERS' CAPITAL (CONTINUED)

The following table illustrates the Partnership's calculation of net income per unit for common and subordinated units:

	Year Ended December 31,		
thousands except per-unit amounts	2013	2012	2011
Net income attributable to Western Gas Partners, LP	$275,136	$134,421	$192,758
Pre-acquisition net (income) loss allocated to Anadarko	(4,637)	(27,435)	(52,599)
General partner interest in net (income) loss	(69,633)	(28,089)	(8,599)
Limited partners' interest in net income	$200,866	$78,897	$131,560
Net income allocable to common units	$200,866	$78,897	$110,542
Net income allocable to subordinated units	—	—	21,018
Limited partners' interest in net income	$200,866	$78,897	$131,560
Net income per unit – basic and diluted			
Common units	$1.83	$0.84	$1.64
Subordinated units	$—	$—	$1.28
Weighted average units outstanding – basic and diluted			
Common units	109,872	93,936	67,333
Subordinated units	—	—	16,431

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. Operating and maintenance expense includes amounts accrued for or paid to affiliates for the operation of the Partnership assets, whether in providing services to affiliates or to third parties, including field labor, measurement and analysis, and other disbursements. A portion of the Partnership's general and administrative expenses is paid by Anadarko, which results in affiliate transactions pursuant to the reimbursement provisions of the Partnership's omnibus agreement. Affiliate expenses do not bear a direct relationship to affiliate revenues, and third-party expenses do not bear a direct relationship to third-party revenues. See Note 2 for further information related to contributions of assets to the Partnership by Anadarko.

Cash management. Anadarko operates a cash management system whereby excess cash from most of its subsidiaries' separate bank accounts is generally swept to centralized accounts. Prior to the Partnership's acquisition of the Partnership assets, third-party sales and purchases related to such assets were received or paid in cash by Anadarko within its centralized cash management system. 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.

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WESTERN GAS PARTNERS, LP
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5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

Note receivable from and amounts 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 $296.7 million and $334.8 million at December 31, 2013 and 2012, 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 10.

Commodity price swap agreements. The Partnership has commodity price swap agreements with Anadarko to mitigate exposure to 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 Granger, Hilight, Hugoton, Newcastle, MGR and Wattenberg assets, with various expiration dates through December 2016. In December 2013, the Partnership extended the commodity price swap agreements for the Hilight and Newcastle assets through December 2014. 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, 2013 excluding the Hilight and Newcastle assets:

per barrel except natural gas	2014		2015		2016
Ethane	$18.36	– $30.53	$18.41	– $23.41	$23.11
Propane	$46.47	– $53.78	$47.08	– $52.99	$52.90
Isobutane	$61.24	– $75.13	$62.09	– $74.02	$73.89
Normal butane	$53.89	– $66.01	$54.62	– $65.04	$64.93
Natural gasoline	$71.85	– $83.04	$72.88	– $81.82	$81.68
Condensate	$75.22	– $83.04	$76.47	– $81.82	$81.68
Natural gas (per MMBtu)	$4.45	– $6.20	$4.66	– $5.96	$4.87

Below is a summary of the fixed prices or ranges on the Partnership's outstanding commodity price swap agreements for the Hilight and Newcastle assets as of December 31, 2013:

per barrel except natural gas	2014	
Propane		$40.38
Normal butane	$64.73	– $66.83
Natural gasoline		$90.89
Condensate		$87.30
Natural gas (per MMBtu)		$3.45

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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	2013	2012	2011
Gains (losses) on commodity price swap agreements related to sales: [1]			
Natural gas sales	$21,382	$37,665	$33,845
Natural gas liquids sales	102,076	66,260	(36,802)
Total	123,458	103,925	(2,957)
Losses on commodity price swap agreements related to purchases [2]	(85,294)	(89,710)	(27,234)
Net gains (losses) on commodity price swap agreements	$38,164	$14,215	$(30,191)

(1) Reported in affiliate natural gas, NGLs 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. For the years ended December 31, 2013, 2012 and 2011, 57%, 64% and 67%, respectively, of the Partnership's gathering, transportation and treating throughput (excluding equity investment throughput and volumes measured in barrels) was attributable to natural gas production owned or controlled by Anadarko. For the years ended December 31, 2013, 2012 and 2011, 56%, 59% and 64%, respectively, of the Partnership's processing throughput (excluding equity investment throughput and volumes measured in barrels) was attributable to natural gas production owned or controlled by Anadarko.

Gas purchase and sale agreements. The Partnership sells substantially all of its natural gas, NGLs, and condensate 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	2013	2012	2011
General and administrative expenses	$16,882	$14,904	$11,754
Public company expenses	7,152	6,830	7,735
Total reimbursement	$24,034	$21,734	$19,489

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.

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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, $0.4 million and $0.3 million for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013, there was $0.6 million of unrecognized compensation expense attributable to the outstanding awards under the WES LTIP, of which $0.5 million will be realized by the Partnership, and which is expected to be recognized over a weighted-average period of 1.4 years.
The following table summarizes WES LTIP award activity for the years ended December 31, 2013, 2012 and 2011:

	2013		2012		2011	
	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	$41.77	25,619	$33.92	23,978	$20.19	17,503
Vested	$41.28	(14,695)	$33.20	(14,260)	$20.51	(15,119)
Granted	$62.49	5,920	$45.91	15,901	$35.66	21,594
Phantom units outstanding at end of year	$49.47	16,844	$41.77	25,619	$33.92	23,978

WGP LTIP and Anadarko Incentive Plans. For the years ended December 31, 2013, 2012 and 2011, the Partnership’s general and administrative expenses included $3.0 million, $3.3 million and $2.5 million, respectively, of equity-based compensation expense, allocated to the Partnership by WGP and 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, $2.9 million, $3.2 million and $1.0 million are reflected as a contribution to partners’ capital in the Partnership’s consolidated statements of equity and partners’ capital for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013, the Partnership estimated that $5.5 million of unrecognized compensation expense attributable to the WGP LTIP and the Anadarko Incentive Plans (excluding performance-based awards) will be allocated to the Partnership over a weighted-average period of 2.1 years.
During the fourth quarter of 2011, the Partnership recorded $9.7 million to partners’ capital in its consolidated financial statements related to accumulated compensation expense attributable to the Anadarko Incentive Plans that was allocated to the Partnership by Anadarko.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. TRANSACTIONS WITH AFFILIATES (CONTINUED)

The Incentive Plan. For the years ended December 31, 2012 and 2011, the Partnership's general and administrative expenses included $68.8 million and $11.4 million, respectively, 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. UARs outstanding under the Incentive Plan as of December 31, 2011 were valued at $634.00 per UAR.

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,					
	2013	2012	2011	2013	2012	2011
thousands	Purchases			Sales		
Cash consideration	$11,211	$24,705	$3,837	$85	$760	$382
Net carrying value	5,309	8,009	1,998	38	393	316
Partners' capital adjustment	$5,902	$16,696	$1,839	$47	$367	$66

Contributions in aid of construction costs from affiliates. During the fourth quarter of 2013, a subsidiary of Anadarko entered into an aid in construction agreement with the Partnership, whereby the Partnership will construct five receipt-point facilities at the Brasada facility that will serve the Anadarko subsidiary. Such subsidiary will reimburse 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	2013	2012	2011
Revenues (1)	$829,258	$704,137	$658,680
Cost of product (1)	129,045	145,250	83,722
Operation and maintenance (2)	56,435	51,237	51,339
General and administrative (3)	23,354	92,847	33,305
Operating expenses	208,834	289,334	168,366
Interest income, net (4)	16,900	16,900	24,106
Interest expense (5)	—	2,766	4,935
Distributions to unitholders (6)	169,150	98,280	68,039
Contributions from noncontrolling interest owners (7)	—	12,588	16,476
Distributions to noncontrolling interest owners (7)	—	6,528	9,437

(1) Represents amounts 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 by the Partnership.

(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 The Incentive Plan and WGP LTIP and Anadarko Incentive Plans within this Note 5).

(4) Represents interest income recognized on the note receivable from Anadarko. For the year ended December 31, 2011, this line item also includes interest income, net on affiliate balances related to the Non-Operated Marcellus Interest, the MGR assets and the Bison assets for periods prior to the acquisition of such assets. Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on the aforementioned assets prior to their acquisition were entirely settled through an adjustment to net investment by Anadarko.

(5) For the year ended December 31, 2012, includes interest expense recognized on the note payable to Anadarko (see Note 10) and interest imputed on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada facility and Lancaster plant. The Partnership repaid the note payable to Anadarko in June 2012, and repaid the reimbursement payable to Anadarko related to the construction of the Brasada facility and Lancaster plant in the fourth quarter of 2012.

(6) Represents distributions paid under the partnership agreement.

(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 on the consolidated statements of income.

6. INCOME TAXES

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

	Year Ended December 31,		
thousands	2013	2012	2011
Current income tax expense (benefit)			
Federal income tax expense (benefit)	$2,304	$(7,555)	$15,248
State income tax expense (benefit)	640	(1,843)	322
Total current income tax expense (benefit)	2,944	(9,398)	15,570
Deferred income tax expense (benefit)			
Federal income tax expense	725	22,328	13,075
State income tax expense (benefit)	(1,039)	7,785	3,505
Total deferred income tax expense (benefit)	(314)	30,113	16,580
Total income tax expense	$2,630	$20,715	$32,150

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	2013	2012	2011
Income before income taxes	$288,582	$170,026	$239,011
Statutory tax rate	— %	— %	— %
Tax computed at statutory rate	$—	$—	$—
Adjustments resulting from:			
Federal taxes on income attributable to Partnership assets pre-acquisition	3,365	17,251	29,502
State taxes on income attributable to Partnership assets pre-acquisition (net of federal benefit)	624	2,206	1,984
Texas margin tax expense (benefit)	(1,359)	1,258	664
Income tax expense	$2,630	$20,715	$32,150
Effective tax rate	1 %	12 %	13 %

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

	December 31,	
thousands	2013	2012
Credit carryforwards	$14	$14
Net current deferred income tax assets	14	14
Depreciable property	(839)	(47,558)
Credit carryforwards	527	541
Other	3	(136)
Net long-term deferred income tax liabilities	(309)	(47,153)
Total net deferred income tax liabilities	$(295)	$(47,139)

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:

thousands	Estimated Useful Life	December 31, 2013	2012
Land	n/a	$2,584	$501
Gathering systems	3 to 47 years	3,673,008	2,911,572
Pipelines and equipment	15 to 45 years	146,008	91,126
Assets under construction	n/a	405,633	422,002
Other	3 to 40 years	11,867	7,191
Total property, plant and equipment		4,239,100	3,432,392
Accumulated depreciation		855,845	714,436
Net property, plant and equipment		$3,383,255	$2,717,956

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. See Note 8.
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.
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.
During 2011, the Partnership recognized a $7.3 million impairment related to certain equipment and materials. The costs of the equipment and materials, previously capitalized as assets under construction and related to a Red Desert complex (see Note 2) expansion project, were deemed no longer recoverable as the expansion project was indefinitely postponed. Also during 2011, following an evaluation of estimated future cash flows, an impairment of $3.0 million was recognized for a transportation pipeline that was impaired to its estimated fair value using Level 3 fair-value inputs.

8. COMPONENTS OF WORKING CAPITAL

A summary of other current assets is as follows:

thousands	December 31, 2013	2012
Natural gas liquids inventory	$2,584	$1,678
Natural gas imbalance receivables	3,605	1,663
Prepaid insurance	2,123	1,897
Other	1,710	1,760
Total other current assets	$10,022	$6,998

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8. COMPONENTS OF WORKING CAPITAL (CONTINUED)

A summary of accrued liabilities is as follows:

	December 31,	
thousands	2013	2012
Accrued capital expenditures	$94,750	$112,311
Accrued plant purchases	21,396	16,350
Accrued interest expense	18,119	15,868
Short-term asset retirement obligations	1,966	1,711
Short-term remediation and reclamation obligations	562	799
Other	218	612
Total accrued liabilities	$137,011	$147,651

9. ASSET RETIREMENT OBLIGATIONS

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

	Year Ended December 31,	
thousands	2013	2012
Carrying amount of asset retirement obligations at beginning of year	$66,723	$64,345
Liabilities incurred	14,143	9,414
Liabilities settled	(1,943)	(786)
Accretion expense	4,326	4,270
Revisions in estimated liabilities	(5,214)	(10,520)
Carrying amount of asset retirement obligations at end of year	$78,035	$66,723

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 Wattenberg system. The liabilities incurred for the year ended December 31, 2013, represented the increase in the capital expansion at the Wattenberg and Hilight systems and the June 2013 completion of the Brasada facility.
Revisions in estimated liabilities for the year ended December 31, 2012, related primarily to the change in the estimated timing of settling the Partnership’s asset retirement obligations at the Wattenberg system. The liabilities incurred for the year ended December 31, 2012, represented the increase in asset retirement obligations primarily related to the capital expansion at the Wattenberg system.

10. DEBT AND INTEREST EXPENSE

The following table presents the Partnership's outstanding debt as of December 31, 2013 and 2012:

	December 31, 2013			December 31, 2012		
thousands	Principal	Carrying Value	Fair Value [(1)]	Principal	Carrying Value	Fair Value [(1)]
4.000% Senior Notes due 2022	$670,000	$673,278	$641,237	$670,000	$673,617	$669,928
5.375% Senior Notes due 2021	500,000	495,173	533,615	500,000	494,661	499,946
2.600% Senior Notes due 2018	250,000	249,718	247,988	—	—	—
Total debt outstanding	$1,420,000	$1,418,169	$1,422,840	$1,170,000	$1,168,278	$1,169,874

(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, 2013 and 2012:

thousands	Carrying Value
Balance as of December 31, 2011	$669,178
Revolving credit facility borrowings	374,000
Issuance of 4.000% Senior Notes due 2022	670,000
Repayment of revolving credit facility	(374,000)
Repayment of note payable to Anadarko	(175,000)
Revolving credit facility borrowings - Swingline	20,000
Repayment of revolving credit facility - Swingline	(20,000)
Other	4,100
Balance as of 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 as of December 31, 2013	$1,418,169

Senior Notes. In August 2013, the Partnership completed the offering of $250.0 million aggregate principal amount of 2.600% Senior Notes due 2018 (the "2018 Notes") at a price to the public of 99.879% of the face amount. Including the effects of the issuance and underwriting discounts, the effective interest rate of the 2018 Notes is 2.806%. Interest is paid semi-annually on February 15 and August 15 of each year. Proceeds (net of underwriting discount of $1.5 million, original issue discount and debt issuance costs) were used to repay amounts then outstanding under the Partnership's $800.0 million senior unsecured revolving credit facility ("RCF").

The 2018 Notes mature on August 15, 2018, unless earlier redeemed. The Partnership may redeem the 2018 Notes in whole or in part, at any time before July 15, 2018, at a redemption price equal to the greater of (i) 100% of the principal amount of the 2018 Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on such 2018 Notes (exclusive of interest accrued to the redemption date) discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined in the indenture governing the 2018 Notes) plus 20 basis points, plus, in either case, accrued and unpaid interest to such redemption date, if any, on the principal amount being redeemed. On or after July 15, 2018, the 2018 Notes may be redeemed, at any time in whole, or from time to time in part, at a price equal to 100% of the principal amount of the 2018 Notes to be redeemed, plus accrued interest on the 2018 Notes to be redeemed to the date of redemption.

10. DEBT AND INTEREST EXPENSE (CONTINUED)

In June 2012, the Partnership completed the offering of $520.0 million aggregate principal amount of 4.000% Senior Notes due 2022. In October 2012, the Partnership issued an additional $150.0 million in aggregate principal amount of 4.000% Senior Notes due 2022. The October 2012 notes and the June 2012 notes were issued under the same indenture and are considered a single class of securities, collectively referred to as the “2022 Notes.”
In May 2011, the Partnership completed the offering of $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the “2021 Notes”). The indentures governing the 2021 Notes, the 2022 Notes, and the 2018 Notes contain customary events of default. At December 31, 2013, the Partnership was in compliance with all covenants under the indentures governing the 2021 Notes, 2022 Notes, and the 2018 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.
In March 2011, the Partnership entered into a forward-starting interest-rate swap agreement to mitigate the risk of rising interest rates prior to the issuance of the 2021 Notes. In May 2011, the Partnership issued the 2021 Notes and terminated the swap agreement, realizing a loss of $1.9 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 March 2011, the Partnership entered into an amended and restated $800.0 million senior unsecured RCF and borrowed $250.0 million under the RCF to repay the Wattenberg term loan (described below). The RCF amended and restated a $450.0 million credit facility, which was originally entered into in October 2009. At December 31, 2013 and 2012, the interest rate on the RCF was 1.67% and 1.71%, respectively. The Partnership is required to pay a quarterly facility fee currently ranging from 0.20% to 0.35% of the commitment amount (whether used or unused), based upon the Partnership’s senior unsecured debt rating. The facility fee rate was 0.25% at December 31, 2013 and 2012. See Note 12.
As of December 31, 2013, the Partnership had no outstanding borrowings, $12.8 million in outstanding letters of credit issued and $787.2 million available for borrowing under the RCF. At December 31, 2013, the Partnership was in compliance with all covenants under the RCF.
The 2021 Notes, the 2022 Notes, the 2018 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, the 2021 Notes, and/or the RCF. See Note 12.

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10. DEBT AND INTEREST EXPENSE (CONTINUED)

In connection with the acquisition of the Non-Operated Marcellus Interest in March 2013, the general partner and another wholly owned subsidiary of Anadarko entered into an indemnification agreement (the “2013 Indemnification Agreement”) whereby such subsidiary 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 or the Anadarko-Operated Marcellus Interest. The 2013 Indemnification Agreement applies to the 2018 Notes. The Partnership’s general partner and WGRI also amended and restated the existing indemnity agreement between them to 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 2013 Indemnification Agreement. See Note 12.

Wattenberg term loan. In connection with the Wattenberg acquisition, in August 2010 the Partnership borrowed $250.0 million under a three-year term loan from a group of banks (“Wattenberg term loan”). The Wattenberg term loan incurred interest at London Interbank Offered Rate (“LIBOR”) plus a margin ranging from 2.50% to 3.50% depending on the Partnership’s consolidated leverage ratio as defined in the Wattenberg term loan agreement. The Partnership repaid the Wattenberg term loan in March 2011 using borrowings from its RCF and recognized $1.3 million of accelerated amortization expense related to its early repayment.

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

	Year Ended December 31,		
thousands	2013	2012	2011
Third parties			
Interest expense on long-term debt	$59,293	$41,171	$20,533
Amortization of debt issuance costs and commitment fees (1)	4,449	4,319	5,297
Capitalized interest	(11,945)	(6,196)	(420)
Total interest expense – third parties	51,797	39,294	25,410
Affiliates			
Interest expense on note payable to Anadarko (2)	—	2,440	4,935
Interest expense on affiliate balances (3)	—	326	—
Total interest expense – affiliates	—	2,766	4,935
Interest expense	$51,797	$42,060	$30,345

(1) For the years ended December 31, 2013 and 2012, includes $1.0 million and $1.1 million, respectively, of amortization of (i) the original issue discount for the June 2012 offering of the 2022 Notes, partially offset by the original issue premium for the October 2012 offering of the 2022 Notes, (ii) original issue discount for the 2021 Notes and (iii) underwriters’ fees. In addition, for the year ended December 31, 2013, includes the amortization of the original issue discount and underwriters’ fees for the 2018 Notes of $0.2 million. For the year ended December 31, 2011, includes $0.5 million of amortization of the original issue discount and underwriters’ fees for the 2021 Notes.

(2) In June 2012, the note payable to Anadarko was repaid in full. See Note payable to Anadarko within this Note 10.

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

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11. 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, 2013 and 2012, asset retirement obligations and other on the consolidated balance sheets included a $1.9 million 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 8.

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 which holds the Wattenberg assets. 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.
In July 2011, the Court denied the defendants' motion to dismiss without ruling on the merits and the case is in the discovery phase. Trial is set for April 2014. 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, 2013, the Partnership had unconditional payment obligations for services to be rendered or products to be delivered in connection with its capital projects of $47.1 million, the majority of which is expected to be paid in the next twelve months. These commitments relate primarily to the continued construction of the Lancaster plant and an expansion project at the Fort Lupton compressor station in the Wattenberg system.

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WESTERN GAS PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

11. COMMITMENTS AND CONTINGENCIES (CONTINUED)

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. 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 2014 and includes an early termination clause.
Rent expense associated with the office, warehouse and equipment leases was $2.8 million, $3.0 million and $4.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.
The amounts in the table below represent existing contractual operating lease obligations as of December 31, 2013, that may be assigned or otherwise charged to the Partnership pursuant to the reimbursement provisions of the omnibus agreement:

thousands	Operating Leases
2014	$309
2015	245
2016	233
2017	157
2018	34
Thereafter	—
Total	$978

12. SUBSEQUENT EVENTS

Effective February 12, 2014, Anthony R. Chase resigned as a director of the Partnership's general partner due to his appointment to the board of directors of Anadarko. In connection with his resignation and in recognition of his service, the board of directors of the Partnership's general partner accelerated the vesting of 1,280 phantom units held by Mr. Chase. Also effective February 12, 2014, Steven D. Arnold was appointed to the board of directors as an independent director and member of the audit committee and special committee of the board of directors.
On February 26, 2014, the Partnership entered into a five-year senior unsecured revolving credit agreement (the "2014 RCF"), amending and restating the RCF, which was originally entered into in March 2011 and had an outstanding balance of $60.0 million immediately prior to closing on the 2014 RCF. The aggregate initial commitments of the 2014 RCF lenders are $1.2 billion and are expandable to a maximum of $1.5 billion. The 2014 RCF matures on February 26, 2019, and bears interest at LIBOR, plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon the Partnership's senior unsecured debt rating. The Partnership is required to pay a quarterly facility fee ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), also based upon its senior unsecured debt rating. As of February 26, 2014, there was $60.0 million outstanding on the 2014 RCF, drawn to repay amounts that were outstanding on the RCF upon entering into the 2014 RCF.
On February 27, 2014, the Partnership announced it agreed to acquire Anadarko's 20% interest in Texas Express Pipeline LLC and Texas Express Gathering LLC, and a 33.33% interest in Front Range Pipeline LLC (collectively, the "TEFR acquisition") for $375.0 million. The Partnership intends to finance the TEFR acquisition, which is expected to close on March 3, 2014, with $6.3 million of cash on hand, the borrowing of $350.0 million on the 2014 WES RCF, and the issuance of 308,490 common units to Anadarko at an implied price of $60.78 per unit. In connection with the TEFR acquisition, the Partnership's general partner and another wholly owned subsidiary of Anadarko will enter into an indemnification agreement (the "TEFR Indemnification Agreement") whereby such subsidiary will indemnify the Partnership's general partner for any recourse liability it may have for 2014 RCF borrowings, or other debt financing, attributable to the TEFR acquisition. The Partnership's general partner and WGRI will also amend and restate the

existing indemnity agreement between them (as discussed in Note 10) to 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 TEFR Indemnification Agreement. The Partnership's general partner and another wholly owned subsidiary of Anadarko will also amend and restate the 2013 Indemnification Agreement (as discussed in Note 10) primarily to conform language among all the indemnity agreements with the Partnership's general partner.

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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, 2013 and 2012. 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
2013				
Revenues	$229,747	$255,126	$278,001	$290,621
Operating income	$64,036	$70,127	$90,188	$97,291
Net income	$52,888	$62,060	$81,776	$89,228
Net income attributable to Western Gas Partners, LP	$50,657	$60,200	$78,400	$85,879
Net income per common unit – basic and diluted (1)	$0.31	$0.41	$0.53	$0.56
2012				
Revenues	$224,676	$220,310	$234,734	$230,867
Operating income (2)	$67,221	$59,280	$61,312	$7,081
Net income (loss) (2)	$57,894	$47,599	$50,002	$(6,184)
Net income (loss) attributable to Western Gas Partners, LP (2)	$53,651	$43,309	$46,579	$(9,118)
Net income (loss) per common unit – basic and diluted (1) (2)	$0.48	$0.33	$0.33	$(0.27)

(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).

(2) During the fourth quarter of 2012, the Partnership was allocated $54.9 million of general and administrative expenses from Anadarko associated with the Incentive Plan (as defined and described in Note 1—Summary of Significant Accounting Policies and Note 5—Transactions with Affiliates).

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 ("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, 2013.

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, 2013, that has materially affected, or is reasonably likely to materially affect, the Partnership's internal control over financial reporting.

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Item 9B. Other Information

On February 26, 2014, the Partnership entered into a five-year senior unsecured revolving credit agreement (the "2014 RCF"), amending and restating the RCF, which was originally entered into in March 2011 and had an outstanding balance of $60.0 million immediately prior to closing on the 2014 RCF. The aggregate initial commitments of the 2014 RCF lenders are $1.2 billion and are expandable to a maximum of $1.5 billion. The 2014 RCF matures on February 26, 2019, and bears interest at LIBOR, plus applicable margins ranging from 0.975% to 1.45%, or an alternate base rate equal to the greatest of (a) the Prime Rate, (b) the Federal Funds Effective Rate plus 0.5%, or (c) LIBOR plus 1%, in each case plus applicable margins currently ranging from zero to 0.45%, based upon the Partnership's senior unsecured debt rating. The Partnership is required to pay a quarterly facility fee ranging from 0.15% to 0.30% of the commitment amount (whether used or unused), also based upon its senior unsecured debt rating. The 2014 RCF contains covenants and customary events of default that are substantially similar to the RCF. As of February 26, 2014, there was $60.0 million outstanding on the 2014 RCF, drawn to repay amounts that were outstanding on the RCF upon entering into the 2014 RCF. The above summary of the 2014 RCF is qualified in its entirety by reference to the 2014 RCF, a copy of which is filed as an exhibit hereto as Exhibit 10.15.
On February 27, 2014, the Partnership announced it agreed to acquire Anadarko's 20% interest in Texas Express Pipeline LLC and Texas Express Gathering LLC, and a 33.33% interest in Front Range Pipeline LLC (collectively, the "TEFR acquisition") for $375.0 million. The Partnership intends to finance the TEFR acquisition, which is expected to close on March 3, 2014, with $6.3 million of cash on hand, the borrowing of $350.0 million on the 2014 WES RCF, and the issuance of 308,490 common units to Anadarko at an implied price of $60.78 per unit. The TEFR acquisition will be consummated pursuant to a contribution agreement (the "Contribution Agreement") dated February 27, 2014, among the Partnership, Anadarko and certain of their affiliates. Pursuant to the Contribution Agreement, Anadarko agreed to indemnify the Partnership against certain losses resulting from any breach of Anadarko's and its affiliates' representations, warranties, covenants or agreements, and for certain other matters. The Partnership agreed to indemnify Anadarko and its affiliates against certain losses resulting from any breach of the Partnership's representations, warranties, covenants or agreements. The above summary of the Contribution Agreements is qualified in its entirety by reference to the Contribution Agreement, a copy of which is filed as an exhibit hereto as Exhibit 2.9.
In connection with the TEFR acquisition, the Partnership's general partner and another wholly owned subsidiary of Anadarko will enter into an indemnification agreement (the "TEFR Indemnification Agreement") whereby such subsidiary will indemnify the Partnership's general partner for any recourse liability it may have for 2014 RCF borrowings, or other debt financing, attributable to the TEFR acquisition. The Partnership's general partner and WGRI will also amend and restate the existing indemnity agreement between them (as discussed in Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K) to 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 TEFR Indemnification Agreement. The Partnership's general partner and another wholly owned subsidiary of Anadarko will also amend and restate the 2013 Indemnification Agreement (as discussed in Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K) primarily to conform language among all the indemnity agreements with the Partnership's general partner.
The Partnership also announced on February 27, 2014, that the board of directors of the Partnership's general partner appointed Jacqueline A. Dimpel as Senior Vice President. Ms. Dimpel also serves as Anadarko's Vice President of Midstream, having succeeded Danny Rea upon his retirement at the end of 2013. In connection with her appointment as Senior Vice President, the expected portion of Ms. Dimpel's compensation that will be allocable to the Partnership by Anadarko includes: (i) an annual base salary in the amount of $81,250 (based on an assumed 25% time allocation); (ii) a bonus target opportunity under Anadarko's annual incentive program equal to 65% of the above base salary; and (iii) Ms. Dimpel will also be eligible to receive future equity awards under the Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan and/or the Western Gas Equity Partners, LP 2012 Long-Term Incentive Plan (collectively, the "Plans") with such amounts as determined by Anadarko's management and, if applicable, approved by the board of directors of WGP GP. A more detailed description of these programs is included under the heading Executive Compensation—Compensation Discussion and Analysis—Elements of compensation under Part III, Item 11 of this Form 10-K. Ms. Dimpel is also eligible to participate in Anadarko's other benefits, including welfare and

retirement benefits, severance benefits and change of control benefits, compensation programs, and other benefits on the same basis as other eligible Anadarko employees, and the Partnership will bear the expenses related to the portion of such benefits allocable to the Partnership.

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PART III

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. 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 consolidated subsidiaries, excluding the Partnership and the general partner, and “affiliates” refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and includes the interests in Fort Union Gas Gathering, LLC (“Fort Union”), White Cliffs Pipeline, LLC (“White Cliffs”), Rendezvous Gas Services, LLC (“Rendezvous”) and Enterprise EF78 LLC (the “Mont Belvieu JV”).

Item 10. Directors, Executive Officers and Corporate Governance

Management of Western Gas Partners, LP

As a limited partnership, we have no directors or officers. Instead, Western Gas Holdings, LLC, 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 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”), Anadarko may in the future combine those roles at its discretion. Our general partner’s limited liability company agreement and our Corporate Governance Guidelines permit the roles of Chairman and CEO to be combined.

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 24, 2014. Directors are appointed for a term of one year.

Name	Age	Position with Western Gas Holdings, LLC
Robert G. Gwin	50	Chairman of the Board
Donald R. Sinclair	56	President, Chief Executive Officer and Director
Benjamin M. Fink	43	Senior Vice President, Chief Financial Officer and Treasurer
Danny J. Rea	55	Senior Vice President and Chief Operating Officer (retired effective December 31, 2013)
Philip H. Peacock	42	Vice President, General Counsel and Corporate Secretary
Steven D. Arnold	53	Director
Milton Carroll	63	Director
James R. Crane	60	Director
Charles A. Meloy	53	Director
Robert K. Reeves	56	Director
David J. Tudor	54	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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	Biography/Qualifications
Robert G. Gwin Age: 50 Houston, Texas Director since: August 2007 Not Independent Officer From: August 2007 to January 2010	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 since 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.
	Biography/Qualifications
Donald R. Sinclair Age: 56 Houston, Texas Director since: October 2009 Not Independent Officer Since: October 2009	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. Prior to 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 a member 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.
	Biography/Qualifications
Benjamin M. Fink Age: 43 Houston, Texas Officer since: May 2009	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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	Biography/Qualifications
Danny J. Rea Age: 55 Houston, Texas Officer since: August 2007	Prior to his retirement on December 31, 2013, Danny J. Rea had served as Senior Vice President and Chief Operating Officer of our general partner since August 2007 and as Vice President, Midstream of Anadarko since May 2007. He also served as a director of our general partner from August 2007 to September 2009. Mr. Rea served as Senior Vice President and Chief Operating Officer of WGP GP from September 2012 to December 2013. Previously, Mr. Rea served as Manager, Midstream Services of Anadarko from May 2004 to May 2007 and Manager, Gas Field Services from August 2000 to May 2004. Mr. Rea joined Anadarko as an engineer in 1981 and held positions of increasing responsibility over his 32 years at Anadarko. He holds a Bachelor of Science degree in Petroleum Engineering from Louisiana Tech University, and a Master of Business Administration degree from the University of Houston. He served on the board of directors for the Wyoming Pipeline Authority from March 2006 until March 2010, currently serves on the board of directors of the Texas Pipeline Association, and is a member of the Gas Processors Association and the Society of Petroleum Engineers.
	Biography/Qualifications
Steven D. Arnold Age: 53 Houston, Texas Director since: February 2014 Independent	Steven D. Arnold was appointed as a director of our general partner and as a member of the special and audit committees of the board of directors 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 its 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 10 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 a strong risk assessment and strategic expertise to the board.
	Biography/Qualifications
Philip H. Peacock Age: 42 Houston, Texas Officer since: August 2012	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 our general partner, 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 and serves on the Board of Directors of The Children’s Fund, Inc.
Milton Carroll Age: 63 Houston, Texas	Biography/Qualifications

Director since: April 2008 Independent	Milton Carroll has served as a director of our general partner and as Chairman of the special committee of the board of directors 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 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: 60 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 and audit committees of the board of directors 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: 53 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 since July 2012, prior to which he serviced as Senior Vice President, Worldwide Operations since 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: 56 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 since 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: 54 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 since April 2008 and served as a member of the special committee from April 2008 to December 2012. Mr. Tudor has served as a director of WGP GP and as Chairman of its audit committee 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 20 generation and transmission cooperatives throughout the U.S. 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 U.S. and Canada. He also currently serves as a director of Wabash Valley Power Association’s Board Risk Oversight Committee and as an external member of the Risk Oversight Committee of the East Kentucky Power Cooperative. 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 board of 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, 2013, except that on March 7, 2013, a Form 4 was filed with respect to Mr. Anthony R. Chase’s acquisition of Partnership common units through a broker-assisted distribution reinvestment plan.

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 the omnibus agreement, we reimburse general and administrative expenses 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 (chairperson), Arnold (since February 2014) 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 2013.

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 (Chairperson), 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 the conflict of interest 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 two meetings in 2013.

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 Chairperson 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 Internet 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 Internet 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. We will post on our Internet website all waivers to or amendments of the Code of Ethics, which are required to be disclosed by applicable law and the NYSE’s Corporate Governance Listing Standards. The information contained on, or connected to, our Internet 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"). 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 the omnibus agreement, 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 2013 were Donald R. Sinclair (the principal executive officer), Benjamin M. Fink (the principal financial officer and principal accounting officer), Danny J. Rea (the principal operating officer; retired effective December 31, 2013) and Philip H. Peacock (the vice president, general counsel and corporate secretary). Compensation paid or awarded by us in 2013 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, 2013, (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
Danny J. Rea	40.0%	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 3, 2014. With the exception of the grants 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 2013, 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 the WGP LTIP; 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 2014 for their performance during the year ended December 31, 2013, under the 2013 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 2013, 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, and personal excess liability insurance; and
- benefits, including medical, dental, vision, flexible spending 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 3, 2014.

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 committee or Anadarko's management team regarding compensation (other than recommendations made by Mr. Sinclair and Mr. Fink 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, the WES LTIP, and the WGP LTIP, and other compensation 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.

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, distribution equivalent rights 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.

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 2013.

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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 distribution equivalent rights with respect to phantom units.

No restricted or phantom units were granted to our named executive officers during 2013.

WES unit options and unit appreciation rights. The WES LTIP also permits the grant of options covering common units and unit appreciation rights. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights 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 unit appreciation rights 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 unit appreciation right 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 unit appreciation rights were granted during 2013.

WES distribution equivalent rights. Distribution equivalent rights are rights to receive all or a portion of the distributions otherwise payable on units during a specified time. Distribution equivalent rights may be granted alone or in combination with another award. Phantom units granted under the WES LTIP in 2013 included distribution equivalent rights.

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, unit appreciation rights, other unit-based awards, cash awards, unit awards, substitute awards and distribution equivalent rights. 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 distribution equivalent rights. 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 2013.

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. To align their interests with those of our unitholders in the growth of our cash flows from operations and related distributions, each of Mr. Sinclair and Mr. Fink was awarded a grant of WGP phantom units in November 2013, with an allocated grant date value of $563,000 and $315,000, respectively. Both of these grants vest in one third increments over a three-year period commencing on the first anniversary of the grant date.

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 2013.

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WGP unit appreciation rights (“UAR”). 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 2013.

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 2013.

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 2013.

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 2013.

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 2013.

WGP distribution equivalent rights (“DERs”). 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.

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 2013.

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, Western Gas Holdings, LLC, 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 fiscal years ended December 31, 2013, 2012 and 2011, 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 2013, 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	2013	283,414	—	843,813	280,588	243,736	123,110	1,774,661
President and	2012	271,298	—	506,296	168,623	—	113,250	1,059,467
Chief Executive Officer	2011	246,779	—	534,435	181,899	177,681	106,296	1,247,090
Benjamin M. Fink	2013	280,904	—	760,623	202,020	191,015	121,704	1,556,266
Senior Vice President, Chief	2012	263,062	—	261,073	—	—	109,813	633,948
Financial Officer and Treasurer	2011	253,506	—	160,420	45,860	136,893	109,220	705,899
Danny J. Rea (6)	2013	130,692	—	—	—	—	56,909	187,601
Senior Vice President and	2012	124,692	—	192,787	127,905	—	52,051	497,435
Chief Operating Officer	2011	115,154	—	191,658	130,336	82,911	49,603	569,662
Philip H. Peacock	2013	121,154	—	70,016	—	58,154	52,482	301,806
Vice President, General Counsel	2012	43,269	—	75,006	—	18,173	17,960	154,408
and Corporate Secretary								

(1) The amounts in this column reflect the base salary compensation allocated to us by Anadarko for the fiscal years ended December 31, 2013, 2012 and 2011.

(2) The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with FASB ASC Topic 718 (without respect to the risk of forfeitures), for non-option stock awards granted pursuant to the WES LTIP, the WGP LTIP and the 2008 and 2012 Anadarko Omnibus Incentive Compensation Plans. For awards of phantom units granted under the WES LTIP and WGP LTIP, the grant date value is determined by multiplying the number of phantom units awarded by the per-unit closing price of the underlying common units on the date of grant. For a discussion of valuation assumptions for the awards under the 2008 and 2012 Anadarko Omnibus Incentive Compensation Plans, see Note 15—Share-Based Compensation in the Notes to Consolidated Financial Statements included under Item 8 of Anadarko's Form 10-K for the year ended December 31, 2013 (which is not, and shall not be deemed to be, incorporated by reference herein). For information regarding the non-option stock awards granted to the named executives in 2013, please see the Grants of Plan-Based Awards Table.

(3)

The amounts in this column reflect the expected allocation to us of the grant date fair value, computed in accordance with FASB ASC Topic 718 (without respect to the risk of forfeitures), for option awards granted pursuant to the 2008 and 2012 Anadarko Omnibus Incentive Compensation Plans. See note (2) above for valuation assumptions. For information regarding the option awards granted to the named executives in 2013, please see the Grants of Plan-Based Awards Table.

(4) The amounts in this column reflect the compensation under the Anadarko annual incentive program expected to be allocated to us for the fiscal years ended December 31, 2013, and allocated to us for the fiscal years ended December 31, 2012 and 2011. The 2013 amounts represent payments which were earned in 2013 and are expected to be paid in early 2014, the 2012 amounts represent payments which were earned in 2012 and paid in early 2013 and the 2011 amounts represent the payments which were earned in 2011 and paid in early 2012. For an explanation of the 2013 annual incentive plan awards, please read Compensation Discussion and Analysis – Analysis of 2013 Compensation Actions – Performance-Based Annual Cash Incentives (Bonuses).

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(5) The amounts in this column reflect the compensation expenses related to Anadarko's retirement and savings plans that were allocated to us for the fiscal years ended December 31, 2013, 2012 and 2011. The 2013 allocated expenses are detailed in the table below:

Name	Retirement Plan Expense	Savings Plan Expense
Donald R. Sinclair	$92,849	$30,261
Benjamin M. Fink	$91,777	$29,927
Danny J. Rea	$42,920	$13,989
Philip H. Peacock	$39,577	$12,905

(6) Mr. Rea retired from Anadarko and his position as Senior Vice President and Chief Operating Officer of our general partner on December 31, 2013. As a result of his retirement prior to annual incentive program payments, he did not receive a 2013 annual incentive plan award.

Grants of Plan-Based Awards in 2013

The following table sets forth information concerning annual incentive awards, stock options, phantom units, restricted stock shares, restricted stock units and performance units granted during 2013 to each of the named executive officers. Except for amounts in the column entitled Exercise or Base Price of Option Awards, the dollar amounts and number of securities included in the table below reflect an allocation based upon the time allocation methodology previously discussed in the Overview section, but also take into account any known future changes in the applicable officer's allocation of time to Partnership business. The awards granted to Mr. Rea in 2013 were forfeited upon his December 31, 2013 retirement and as a result there will be no expense allocated to us for these awards.

	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards (2)			All Other Stock Awards: Number of Shares of Stock or Units (#) (3)	All Other Option Awards: Number of Securities Underlying Options (#) (4)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) (5)
Name and Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)				
Donald R. Sinclair										
—	—	203,113	243,736							
11/06/13							3,057			281,305
11/06/13								10,818	92.02	280,588
11/20/13 (6)							13,683			562,508
Benjamin M. Fink										
—	—	159,179	191,015							
03/07/13							2,935			243,039
06/07/13							512			45,055
06/07/13								1,453	87.98	44,896
11/06/13							1,712			157,520
11/06/13								6,058	92.02	157,124
11/20/13 (6)							7,663			315,009
Danny J. Rea										
—	—	82,227	98,673							

11/06/13								4,442	92.02	—	
11/06/13							897			—	
11/06/13				356	1,318	2,636				—	
Philip H. Peacock											
—	—	48,462	58,154								
03/07/13							846			70,016	

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(1) Reflects the estimated 2013 cash payouts allocable to us under Anadarko's annual incentive plan. If threshold levels of performance are not met, then the payout can be zero. The maximum value reflects the maximum amount allocable to us consistent with the methodologies set forth in the services and secondment agreement. The expense expected to be allocated to us for the actual bonus payouts under the annual incentive program for 2013 is reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table. For additional discussion of Anadarko's annual incentive plan please read Compensation Discussion and Analysis — Analysis of 2013 Compensation Actions — Performance-Based Annual Cash Incentives (Bonuses) contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014.

(2) Reflects the estimated future payout allocable to us under Anadarko's performance units awarded in 2013. Under the performance unit program, participants may earn from 0% to 200% of the targeted award based on Anadarko's relative total shareholder return performance over a specified performance period. Fifty percent of this award is tied to a two-year performance period and the remaining fifty percent is tied to a three-year performance period. If earned, the awards are to be paid in cash rather than equity. The threshold value represents the minimum payment (other than zero) that may be earned. For additional discussion of Anadarko's performance unit awards please read Compensation Discussion and Analysis — Analysis of 2013 Compensation Actions — Equity Compensation contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014.

(3) Reflects the allocable number of phantom units under the WGP LTIP and restricted stock shares and restricted stock units awarded in 2013 under the Omnibus Plan. These awards vest equally over three years, beginning with the first anniversary of the grant date. Executive officers receive distribution equivalent rights on the phantom units and dividends on the restricted stock shares. For restricted stock units, dividend equivalents are reinvested in shares of Anadarko common stock and paid upon the applicable vesting of the underlying award.

(4) Reflects the allocable number of Anadarko stock options each named executive officer was awarded in 2013. These awards vest equally over three years, beginning with the first anniversary of the date of grant and have a term of seven years.

(5) The amounts included in the Grant Date Fair Value of Stock and Option Awards column represent the expected allocation to us of the grant date fair value of the awards made to named executives in 2013 computed in accordance with FASB ASC Topic 718. The value ultimately realized by the executive upon the actual vesting of the award(s) or the exercise of the stock option(s) may or may not be equal to the determined value. For awards of phantom units granted under the WGP LTIP, the grant date value is determined by multiplying the number of phantom units awarded by the per-unit closing price of the underlying common units on the date of grant. For a discussion of valuation assumptions for the awards under the Omnibus Plan, see Note 15—Share-Based Compensation in the Notes to Consolidated Financial Statements under Item 8 of Anadarko's Form 10-K for the year ended December 31, 2013 (which is not, and shall not be deemed to be, incorporated by reference herein).

(6) Reflects an award of phantom units granted under the WGP LTIP.

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Outstanding Equity Awards at Fiscal Year-End 2013

The following table reflects outstanding equity awards as of December 31, 2013, for each of the named executive officers, including awards under the 2008 and 2012 Anadarko Omnibus Incentive Compensation Plans, the WES LTIP and the WGP LTIP. The market values shown are based on Anadarko's closing stock price on December 31, 2013, of $79.32, unless otherwise noted. Except for amounts in the column entitled Option Exercise Price, the dollar amounts and number of securities included in the table below reflect an allocation based upon each officer's allocation of time to Partnership business at December 31, 2013.

					Stock Awards			
							Equity Incentive Plan Awards Performance Units (3)	
	Option Awards (1) Number of Securities Underlying Unexercised Options				Restricted Stock Shares/Units and Unit Value Rights (2)			
Name	Exercisable (#)	Unexercisable (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Market Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Donald R. Sinclair	5,465	—	62.09	11/17/17	752	59,649		
	4,229	2,114	78.95	11/16/18	1,604	127,229		
	2,168	4,337	70.70	11/05/19	3,064	243,036		
	—	10,818	92.02	11/06/20	3,299	203,515 (4)		
					4,788	295,372 (4)		
					13,683	540,615 (5)		
Benjamin M. Fink	1,598	—	65.99	03/13/15	660	52,351		
	5,000	—	33.07	03/06/16	2,108	167,207		
	2,831	—	72.11	03/05/17	2,935	232,804		
	1,047	524	81.02	03/04/18	514	40,770		
	—	1,453	87.98	06/07/20	1,715	136,034		
	—	6,058	92.02	11/06/20	7,663	302,765 (5)		
Danny J. Rea	4,240	—	59.87	11/06/14	—	—	581	46,085
	7,640	—	35.18	11/04/15	—	—	362	28,714
	3,080	—	65.44	11/10/16	—	—	225	17,847
	4,179	—	63.34	12/31/16	—	—		
	2,858	—	83.95	12/31/16	—	—		
	1,645	—	70.70	12/31/16	—	—		
	—	—	—	—	723	57,348		

Philip H. Peacock		
	846	67,105

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(1) The table below shows the vesting dates for the respective unexercisable stock options listed in the above Outstanding Equity Awards Table:

Vesting Date	Donald R. Sinclair	Benjamin M. Fink	Danny J. Rea	Philip H. Peacock
03/04/2014	—	524	—	—
06/07/2014	—	484	—	—
11/05/2014	2,168	—	—	—
11/06/2014	3,606	2,020	—	—
11/16/2014	2,114	—	—	—
06/07/2015	—	484	—	—
11/05/2015	2,169	—	—	—
11/06/2015	3,606	2,019	—	—
06/07/2016	—	485	—	—
11/06/2016	3,606	2,019	—	—

(2) The table below shows the vesting dates for the respective phantom units, restricted stock shares and restricted stock units listed in the above Outstanding Equity Awards Table:

Vesting Date	Donald R. Sinclair	Benjamin M. Fink	Danny J. Rea	Philip H. Peacock
03/03/2014	—	1,054	—	—
03/04/2014	—	660	—	—
03/07/2014	—	978	—	282
06/07/2014	—	172	—	
09/04/2014	—	—	—	362
11/05/2014	802	—	—	—
11/06/2014	1,022	572	—	—
11/08/2014	—	—	—	—
11/14/2014	2,394	—	—	—
11/16/2014	4,051	—	—	—
11/20/2014	4,562	2,554	—	—
03/03/2015	—	1,054	—	—
03/07/2015	—	979	—	282
06/07/2015	—	171	—	—
09/04/2015	—	—	—	361
11/05/2015	802	—	—	—
11/06/2015	1,021	571	—	—
11/14/2015	2,394	—	—	—
11/20/2015	4,561	2,554	—	—
03/07/2016	—	978	—	282
06/07/2016	—	171	—	—
11/06/2016	1,021	572	—	—
11/20/2016	4,560	2,555	—	—

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(3) The table below shows the performance periods for the respective performance units listed in the above Outstanding Equity Awards Table. As a result of Mr. Rea's retirement, his outstanding performance units were pro-rated based on the number of months he worked during the applicable performance periods. Except for the awards with performance periods beginning January 1, 2013, the number of outstanding units disclosed is calculated based on Anadarko's performance to date for each award. As of December 31, 2013, the performance to date calculation for the awards with performance periods beginning January 1, 2013 was 0%, however, in accordance with the rules, we have disclosed the threshold performance payout of 54%. The estimated payout percentages reflect our relative performance ranking as of December 31, 2013, and are not necessarily indicative of what the payout percentage earned will be at the end of the performance period.

Performance Period	APC Performance to Date Payout %	Danny J. Rea Performance Units
1/1/2011 to 12/31/2013	92%	581
1/1/2012 to 12/31/2013	54%	217
1/1/2012 to 12/31/2014	54%	145
1/1/2013 to 12/31/2014	54%	135
1/1/2013 to 12/31/2015	54%	90

(4) These awards represent grants of phantom units under the WES LTIP. The market values for these awards are based on the closing common unit price for the Partnership on December 31, 2013, of $61.69.

(5) These awards represent grants of phantom units under the WGP LTIP. The market values for these awards are based on the closing common unit price for WGP on December 31, 2013 of $39.51.

Option Exercises and Stock Vested in 2013

The following table reflects Anadarko option awards exercised in 2013 and Anadarko stock awards and WES LTIP phantom units that vested in 2013. The dollar amounts and number of securities included in the table below reflect an allocation based upon the time allocation previously discussed in the Overview section.

Name	Option Awards		Stock Awards	
	Number of Shares Acquired on Exercise (#) (1)	Value Realized on Exercise ($) (1)	Number of Shares Acquired on Vesting (#) (2)	Value Realized on Vesting ($) (2)
Donald R. Sinclair	—	—	8,126	573,841
Benjamin M. Fink	—	—	2,111	169,956
Danny J. Rea	—	—	2,524	219,601
Philip H. Peacock	—	—	362	33,362

(1) Shares acquired and values realized on exercise include options exercised in 2013. The actual value ultimately realized by the named executive officer may be more or less than the realized value calculated in the above table depending on the timing in which the named executive officer held or sold the stock associated with the exercise.

(2) Shares acquired and values realized on vesting reflect the taxable value to the named executive officer as of the date of the vesting in 2013 of restricted stock shares or units, performance units, or phantom units. For restricted stock shares or units and phantom units, the actual value ultimately realized by the named executive officer may be more or less than the value realized calculated in the above table depending on the timing in which the named executive officer held or sold the stock associated with the exercise or vesting occurrence.

Pension Benefits for 2013

Anadarko maintains both funded, tax-qualified defined benefit pension plans and unfunded nonqualified pension benefit plans. The nonqualified pension benefit plans are designed to provide for supplementary pension benefits due to limitations imposed by the Internal Revenue Code that restrict the amount of benefits payable under tax-qualified plans. Our named executive officers are eligible to participate in these plans. Under the omnibus agreement, a portion of the annual expense related to these plans is reimbursed by us to Anadarko. The allocated expense for each named executive officer is included in the All Other Compensation column of the Summary Compensation Table. We have not included a pension benefits table as Anadarko does not allocate expense to the Partnership upon an employee's retirement and the subsequent payment of benefits under such pension plans. For additional discussion on Anadarko's pension benefits, please read Compensation Discussion and Analysis — Indirect Compensation Elements — Retirement Benefits contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014.

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Nonqualified Deferred Compensation for 2013

Anadarko maintains a deferred compensation plan and a savings restoration plan for certain employees, including our named executive officers. The deferred compensation plan allows certain employees to voluntarily defer receipt of up to 75% of their salary and/or up to 100% of their annual incentive bonus payments. The savings restoration plan accrues a benefit substantially equal to the amount that, in the absence of certain Internal Revenue Code limitations, would have been allocated to their account as matching contributions under Anadarko's 401(k) Plan. Pursuant to the terms of the omnibus agreement, a portion of the expense related to these plans is reimbursed by us to Anadarko. The allocated expense for each named executive officer is included in the All Other Compensation column of the Summary Compensation Table. We have not included a nonqualified deferred compensation table as Anadarko does not allocate expense to the Partnership upon distribution of such balances. For additional discussion on Anadarko's nonqualified deferred compensation benefits please read Compensation Discussion and Analysis — Indirect Compensation Elements — Retirement Benefits and Other Benefits sections contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014.

Potential Payments Upon Termination or Change of Control

In the event of a Change of Control (as defined below) of the general partner, the only payments that we would be responsible for paying to our named executive officers relate to our allocated share of the accelerated vesting of unvested awards under the WES LTIP. Similarly, we would be responsible for paying our allocated share of any accelerated vesting of awards under the WGP LITP if a Change of Control were to occur at WGP GP. We have provided estimates of the accelerated vesting applicable to currently outstanding WES LTIP and WGP LTIP awards below, but we cannot know the value that any named executive officer could receive upon a Change in Control until such an event actually occurs.

A "Change of Control" is generally defined within the WES LTIP as any one of the following occurrences: (a) any "person" or "group" within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an affiliate of our general partner, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in our general partner; (b) the members of our general partner approve, in one or a series of transactions, a plan of complete liquidation of our general partner; (c) the sale or other disposition by the general partner of all or substantially all of its assets in one or more transactions to any person other than an affiliate of our general partner; or (d) our general partner or an affiliate of our general partner ceases to be our general partner. The WGP LTIP defines a Change of Control in substantially the same manner as the WES LTIP, with reference to a change of control at WGP GP. With respect to an award under the WES LTIP or WGP LTIP that is subject to Section 409A of the Code for which a Change of Control would accelerate the timing of payment thereunder, "Change of Control" means a change in the ownership or effective control of the company, or in the ownership of a substantial portion of the assets of the company (as defined in Section 409A of the Code and the guidance issued thereunder), but only to the extent inconsistent with the above definition, and only to the minimum extent necessary to comply with Section 409A of the Code.

The award values under these plans as of December 31, 2013, are set forth in the table below, and reflect an allocation of value based upon each named executive officer's allocation of time to Partnership business at December 31, 2013.

Name	Accelerated WES/WGP LTIP Awards [1]
Donald R. Sinclair	$1,039,472
Benjamin M. Fink	$302,749
Philip H. Peacock	$—

(1)

WES LTIP phantom units are valued based on the closing WES common unit price of $61.69 on December 31, 2013; WGP LTIP phantom units are valued based on the closing WGP common unit price of $39.51 on December 31, 2013.

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There were no severance payments incurred in connection with Mr. Rea's retirement from Anadarko and from his position as Senior Vice President and Chief Operating Officer of our general partner on December 31, 2013, and no amounts will be allocated to the Partnership with respect to his retirement. Accordingly, the tables in this section do not reflect any severance amounts for Mr. Rea.

We have not entered into any employment agreements with our named executive officers, nor do we manage any severance plans. However, our named executive officers are eligible for certain benefits provided by Anadarko. Currently, we are not allocated any expense for these agreements or plans, but for disclosure purposes we are presenting allocated expenses of the potential payments provided by Anadarko in the event of termination or Change of Control of Anadarko. For the definition of a Change of Control of Anadarko, please read Potential Payments Upon Termination or Change of Control contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014. Values reflect each named executive officer's allocation of time to Partnership business at December 31, 2013, and exclude those benefits generally provided to all salaried employees. For additional discussion related to these termination scenarios, please read Compensation Discussion and Analysis — Indirect Compensation Elements — Severance Benefits contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014.

The following tables reflect the expenses that may be allocated to the Partnership by Anadarko as of December 31, 2013, in connection with potential payments to our named executive officers under existing contracts, agreements, plans or arrangements, whether written or unwritten, with Anadarko, for various scenarios involving a Change of Control of Anadarko or termination of employment from Anadarko for each named executive officer, assuming a December 31, 2013, termination date, and, where applicable, using the closing price of Anadarko's common stock of $79.32 (as reported on the NYSE as of December 31, 2013). For general definitions that apply to the termination of employment from Anadarko scenarios detailed below, please read Potential Payments Upon Termination or Change of Control contained within Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014. Actual amounts will be determinable only upon the termination or Change in Control event. As of December 31, 2013, none of our named executive officers, except for Mr. Rea, were eligible for retirement.

Involuntary For Cause or Voluntary Termination

	Mr. Sinclair	Mr. Fink	Mr. Peacock
Cash Severance	$—	$—	$—
Total	$—	$—	$—

Involuntary Not For Cause Termination

	Mr. Sinclair	Mr. Fink	Mr. Peacock
Cash Severance (1)	$840,000	$787,050	$—
Pro-rata Bonus for 2013 (2)	243,736	191,015	—
Accelerated Anadarko Equity Compensation (3)	468,038	629,142	124,413
Health and Welfare Benefits (4)	61,026	47,552	—
Total	$1,612,800	$1,654,759	$124,413

(1) Messrs. Sinclair's and Fink's values assume two times base salary plus one times target bonus multiplied by their allocation percentages in effect as of December 31, 2013. No value has been disclosed for Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

(2) Payment, if provided, will be paid at the end of the performance period based on actual performance. The values for Messrs. Sinclair and Fink reflect the allocated portion of their actual bonuses awarded under the AIP. For additional discussion of this program please see section Compensation Discussion and Analysis — Analysis of 2013 Compensation Actions — Performance-Based Annual Cash Incentives (Bonuses) of Anadarko's proxy statement for its annual meeting of stockholders, which is expected to be filed no later than April 3, 2014. No value has been disclosed for Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options and the value of unvested restricted stock shares and restricted stock units, under Anadarko equity plans, all as of December 31, 2013.

(4) Messrs. Sinclair's and Fink's values represent 24 months of health and welfare benefit coverage. These amounts are present values determined in accordance with GAAP. These values reflect their allocation percentage in effect as of December 31, 2013. No value has been disclosed for Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

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Change of Control: Involuntary Termination or Voluntary For Good Reason

	Mr. Sinclair	Mr. Fink	Mr. Peacock
Cash Severance (1)	$1,489,875	$1,027,496	$—
Pro-rata Bonus for 2013 (2)	243,736	191,015	—
Accelerated Anadarko Equity Compensation (3)	468,038	629,142	124,413
Accelerated WES/WGP Equity Compensation (4)	1,039,472	302,749	—
Supplemental Pension Benefits (5)	—	—	—
Nonqualified Deferred Compensation (6)	90,000	59,400	—
Health and Welfare Benefits (7)	91,650	47,552	—
Total	$3,422,771	$2,257,354	$124,413

(1) Messrs. Sinclair's and Fink's values assume 2.9 times and two times, respectively, the sum of base salary plus the highest bonus paid in the past three years and reflect their allocation percentages in effect as of December 31, 2013, per the terms of their key employee change of control agreements with Anadarko. No value has been disclosed for Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

(2) Messrs. Sinclair's and Fink's values assume the full-year equivalent of their highest annual bonus allocated to us over the past three years. No value has been disclosed for Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

(3) Reflects the in-the-money value of unvested stock options, the value of unvested restricted stock shares and restricted stock units granted under Anadarko equity plans, all as of December 31, 2013. All values reflect each named executive officer's allocation percentage in effect as of December 31, 2013.

(4) Reflects the value of unvested WES and WGP LTIP phantom units based on the applicable closing common unit price of $61.69 and $39.51, respectively, on December 31, 2013. All values reflect each named executive officer's allocation percentage in effect as of December 31, 2013.

(5) Under the terms of their change of control agreements, Messrs. Sinclair and Fink would receive a special retirement benefit enhancement that is equivalent to the additional supplemental pension benefits that would have accrued under Anadarko's retirement plan assuming they were eligible for subsidized early retirement benefits and include additional special pension credits. The value of this benefit has not been included in this table as Anadarko does not allocate expense to the partnership for distribution of these benefits. If Anadarko were to allocate this expense to the Partnership, assuming their allocation percentages in effect as of December 31, 2013, the expense would be as follows: Mr. Sinclair—$139,739 and Mr. Fink—$69,627.

(6) Messrs. Sinclair's and Fink's values reflect an additional three years and two years, respectively, of employer contributions into the savings restoration plan at their current contribution rate to the Plan and are based on their allocation percentages in effect as of December 31, 2013, per the terms of their key employee change of control agreements with Anadarko. No value has been disclosed for Mr. Peacock as he is not eligible for this additional benefit.

(7) Messrs. Sinclair's and Fink's values represent 36 months and 24 months, respectively, of health and welfare benefit coverage. All amounts are present values determined in accordance with GAAP and reflect their allocation percentages in effect as of December 31, 2013. No value has been disclosed for the Mr. Peacock as he receives the same benefits as generally provided to all salaried employees.

Disability

	Mr. Sinclair	Mr. Fink	Mr. Peacock
Cash Severance	$—	$—	$—
Accelerated Anadarko Equity Compensation (1)	468,038	629,142	124,413
Health and Welfare Benefits (2)	152,934	186,945	77,743
Total	$620,972	$816,087	$202,156

(1)

Reflects the in-the-money value of unvested stock options and the value of unvested restricted stock shares and restricted stock units granted under Anadarko equity plans, all as of December 31, 2013. All values reflect each named executive officer's allocation percentage in effect as of December 31, 2013.

(2) Values reflect the continuation of additional death benefit coverage provided to certain employees of Anadarko until age 65. All amounts are present values determined in accordance with GAAP and reflect each named executive officer's allocation percentage in effect as of December 31, 2013.

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Death

	Mr. Sinclair	Mr. Fink	Mr. Peacock
Cash Severance	$—	$—	$—
Accelerated Anadarko Equity Compensation (1)	468,038	629,142	124,413
Life Insurance Proceeds (2)	1,033,592	1,023,256	426,357
Total	$1,501,630	$1,652,398	$550,770

(1) Reflects the in-the-money value of unvested stock options and the value of unvested restricted stock shares and restricted stock units granted under Anadarko equity plans, all as of December 31, 2013. All values reflect each named executive officer's allocation percentage in effect as of December 31, 2013.

(2) Values include amounts payable under additional death benefits provided to certain employees of Anadarko. These liabilities are not insured, but are self-funded by Anadarko. Proceeds are not exempt from federal taxes. Values shown include an additional tax gross-up amount to equate benefits with non-taxable life insurance proceeds. Values are based on each named executive officer's allocation percentage in effect as of December 31, 2013, and exclude death benefit proceeds from programs available to all employees.

Director Compensation

Officers or employees of Anadarko who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Non-employee directors of our general partner receive compensation for their board service and for attending meetings of the board of directors of our general partner and committees of the board pursuant to the director compensation plan approved by the board of directors in May 2013. Such compensation consists of the following:

- an annual retainer of $70,000 for each board member;
- an annual retainer of $2,000 for each member of the audit committee, or $22,000 for the committee chair;
- an annual retainer of $2,000 for each member of the special committee, or $22,000 for the committee chair;
- a fee of $2,000 for each board meeting attended;
- a fee of $2,000 for each committee meeting attended; and
- annual grants of phantom units with a value of approximately $80,000 on the date of grant, all of which vest 100% on the first anniversary of the date of grant (with vesting to be accelerated upon a change of control of our general partner or Anadarko). The non-employee directors received such a grant of phantom units on May 9, 2013.

In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees and for costs associated with participation in continuing director education programs. Each director is fully indemnified by us, pursuant to individual indemnification agreements and our partnership agreement, for actions associated with being a director to the fullest extent permitted under Delaware law.

The following table sets forth information concerning total director compensation earned during the 2013 fiscal year by each non-employee director:

Name	Fees Earned or Paid in Cash	Stock Awards (1)	Option Awards	Non-Equity Incentive Plan Compensation	All Other Compensation	Total
Milton Carroll	$101,500	$79,987	$—	$—	$—	$181,487
Anthony R. Chase	93,500	79,987	—	—	—	173,487
James R. Crane	93,500	79,987	—	—	—	173,487
David J. Tudor	107,500	79,987	—	—	—	187,487

(1) The amounts included in the Stock Awards column represent the grant date fair value of non-option awards made to directors in 2013, computed in accordance with FASB ASC Topic 718. For a discussion of valuation assumptions, see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K. As of December 31, 2013, each of the non-employee directors had 1,280 outstanding phantom units. Mr. Chase's outstanding phantom unit grant was vested as of the date of his resignation from the board of directors on February 12, 2014.

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The following table contains the grant date fair value of phantom unit awards made to each non-employee director during 2013:

Name	Grant Date	Phantom Units (#)	Grant Date Fair Value of Stock and Option Awards ($) (1)
Milton Carroll	May 9	1,280	79,987
Anthony R. Chase	May 9	1,280	79,987
James R. Crane	May 9	1,280	79,987
David J. Tudor	May 9	1,280	79,987

(1) The amounts included in the Grant Date Fair Value of Stock and Option Awards column represent the grant date fair value of the awards made to non-employee directors in 2013 computed in accordance with FASB ASC Topic 718. The value ultimately realized by a director upon the actual vesting of the award(s) may or may not be equal to the determined value.

Compensation Committee Interlocks and Insider Participation

As previously discussed, our general partner's board of directors is not required to maintain, and does not maintain, a compensation committee. Messrs. Gwin, Meloy, Sinclair, and Reeves, who are directors of our general partner, are also executive or corporate officers of Anadarko. However, all compensation decisions with respect to each of these persons are made by Anadarko and none of these individuals receive any compensation directly from us or our general partner for their service as directors. Please read Item 13 below in this Form 10-K for information about relationships among us, our general partner and Anadarko.

Compensation Committee Report

Neither we nor our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above and based on this review and discussion has approved it for inclusion in this Form 10-K.

The board of directors of Western Gas Holdings, LLC:

Robert G. Gwin
Steven D. Arnold
Milton Carroll
James R. Crane
Charles A. Meloy
Robert K. Reeves
Donald R. Sinclair
David J. Tudor

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of our common units and WGP common units held by the following as of February 24, 2014:

- each member of the board of directors of our general partner;
- each named executive officer of our general partner;
- all directors and officers of our general partner as a group; and
- Anadarko and its affiliates.

Name and Address of Beneficial Owner [(1)]	WES Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	WGP Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Anadarko Petroleum Corporation [(2)]	49,745,334	42.29%	199,137,365	90.97%
Robert G. Gwin	10,000	*	200,000	*
Donald R. Sinclair [(3)]	107,972	*	300,000	*
Benjamin M. Fink	2,213	*	12,500	*
Danny J. Rea	18,247	*	40,000	*
Philip H. Peacock	—	*	7,500	*
Steven D. Arnold	31,000	*	7,500	*
Milton Carroll [(3)] [(4)]	4,157	*	4,000	*
James R. Crane [(3)] [(4)]	802,518	*	135,000	*
Charles A. Meloy	3,000	*	5,000	*
Robert K. Reeves	9,000	*	9,000	*
David J. Tudor [(3)]	11,153	*	4,074	*
All directors and executive officers as a group (11 persons) [(3)]	999,260	*	724,574	*

*Less than 1%

(1) The address for all beneficial owners in this table is 1201 Lake Robbins Drive, The Woodlands, Texas 77380.

(2) Anadarko Petroleum Corporation is the ultimate parent company of Western Gas Resources, Inc. and Anadarko Marcellus Midstream, L.L.C. and the general partner of WGP and may, therefore, be deemed to beneficially own the units held by Western Gas Resources, Inc., Anadarko Marcellus Midstream, L.L.C. and WGP.

(3) Does not include (a) 1,280 phantom units that were granted to each of Messrs. Carroll, Crane and Tudor and 10,782 phantom units granted to Mr. Sinclair under the WES LTIP, and (b) an aggregate of 26,758 phantom units that were granted to Messrs. Sinclair and Fink under the WGP LTIP. WES phantom units granted to the independent directors of WES vest 100% on the first anniversary of the date of the grant, and Mr. Sinclair’s WES phantom unit awards vest pro-rata over three years. Each vested phantom unit entitles the holder to receive a common unit or, in the discretion of our general partner’s board of directors, cash equal to the fair market value of a common unit. Holders of phantom units are entitled to distribution equivalents on a current basis. Holders of phantom units have no voting rights until such time as the phantom units become vested and common units are issued to such holders.

(4) Includes (a) 2,000 and 670,600 WES units held by Messrs. Carroll and Crane, respectively, and (b) 4,000 WGP units held by Mr. Carroll, in margin accounts.

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The following table sets forth the number of shares of common stock of Anadarko owned by each of the named executive officers and directors of our general partner and all directors and executive officers of our general partner as a group as of February 24, 2014:

Name and Address of Beneficial Owner (1)	Shares of Common Stock Owned Directly or Indirectly (2)	Shares Underlying Options Exercisable Within 60 Days (2)	Total Shares of Common Stock Beneficially Owned (2)	Percentage of Total Shares of Common Stock Beneficially Owned (2)
Robert G. Gwin (3)	61,258	345,202	406,460	*
Donald R. Sinclair (3)	7,115	15,816	22,931	*
Benjamin M. Fink (4)	6,336	12,220	18,556	*
Danny J. Rea (3)	11,214	59,104	70,318	*
Philip H. Peacock (4)	3,137	—	3,137	*
Steven D. Arnold	13,600	—	13,600	*
Milton Carroll	—	—	—	
James R. Crane	—	—	—	
Charles A. Meloy (3)	107,802	198,594	306,396	*
Robert K. Reeves (3)	156,240	288,378	444,618	*
David J. Tudor	—	—	—	*
All directors and executive officers as a group (11 persons)	366,702	919,314	1,286,016	*

*Less than 1%

(1) The address for all beneficial owners in this table is 1201 Lake Robbins Drive, The Woodlands, Texas 77380.

(2) As of January 31, 2014, there were 503.8 million shares of Anadarko Petroleum Corporation common stock issued and outstanding.

(3) Does not include unvested restricted stock units of Anadarko Petroleum Corporation held by the following individuals in the amounts indicated: Robert G. Gwin—30,432; Donald R. Sinclair—7,226; Benjamin M. Fink—2,477; Charles A. Meloy—31,195; Robert K. Reeves—27,792; and a total of 99,122 unvested restricted stock units are held by the directors and executive officers as a group. Restricted stock units typically vest equally over three years beginning on the first anniversary of the date of grant, and upon vesting are payable in Anadarko common stock, subject to applicable tax withholding. Holders of restricted stock units receive dividend equivalents on the units, but do not have voting rights. Generally, a holder will forfeit any unvested restricted units if he or she terminates voluntarily or is terminated for cause prior to the vesting date. Holders of restricted stock units have the ability to defer such awards.

(4) Includes unvested shares of restricted common stock of Anadarko Petroleum Corporation held by the following individuals in the amounts indicated: Benjamin M. Fink—6,336; Philip H. Peacock—3,137; and a total of 9,473 unvested shares of restricted common stock are held by the directors and executive officers as a group. Restricted stock awards typically vest equally over three years beginning on the first anniversary of the date of grant. Holders of restricted stock receive dividends on the shares and also have voting rights. Generally, a holder of restricted stock will forfeit any unvested restricted shares if he or she terminates voluntarily or is terminated for cause prior to the vesting date.

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The following table sets forth owners of 5% or greater of our units, other than Anadarko, the holdings of which are listed in the first table of this Item 12.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Units	Tortoise Capital Advisors, L.L.C. 11550 Ash Street Suite 300 Leawood, KS 66211	7,226,800 [1]	6.14%
Common Units	Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars Third Floor Los Angeles, CA 90067	6,002,546 [2]	5.10%

(1) Based upon its Schedule 13G filed February 11, 2014, with the SEC with respect to Partnership securities held as of December 31, 2013, Tortoise Capital Advisors, L.L.C. has shared voting power as to 6,657,722 common units and shared dispositive power as to 7,226,800 common units.

(2) Based upon its Schedule 13G filed February 4, 2014, with the SEC with respect to Partnership securities held as of December 31, 2013, Kayne Anderson Capital Advisors, L.P. has shared voting and dispositive power as to 6,002,546 common units.

Securities Authorized for Issuance Under Equity Compensation Plan

The following table sets forth information with respect to the securities that may be issued under the WES LTIP as of December 31, 2013. For more information regarding the WES LTIP, which did not require approval by our unitholders, please read Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K and the caption Western Gas Partners, LP 2008 Long-Term Incentive Plan under Item 11 of this Form 10-K.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by security holders	—	—	—
Equity compensation plans not approved by security holders [1]	16,844	— [2]	2,139,027
Total	16,844	—	2,139,027

(1) The board of directors of our general partner adopted the WES LTIP in connection with the initial public offering of our common units.

(2) Phantom units constitute the only rights outstanding under the WES LTIP. Each phantom unit that may be settled in common units entitles the holder to receive, upon vesting, one common unit with respect to each phantom unit, without payment of any cash. Accordingly, there is no reportable weighted-average exercise price.

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Item 13. Certain Relationships and Related Transactions, and Director Independence

As of February 24, 2014, WGP owned 49,296,205 common units representing a 41.1% limited partner interest in us, and our general partner owned 2,400,467 general partner units, representing a 2.0% general partner interest in us, as well as all of the incentive distribution rights ("IDRs"). In addition, as of February 24, 2014, Anadarko Marcellus Midstream, L.L.C. ("AMM"), a subsidiary of Anadarko, separately held 449,129 common units, representing a 0.4% limited partner interest in the Partnership.

Distributions and Payments to Our General Partner, WGP and AMM

The following table summarizes the distributions and payments made by us to our general partner, WGP and AMM and to be made to us by our general partner, WGP and AMM in connection with our ongoing operation and liquidation. These distributions and payments were determined, before our initial public offering ("IPO"), by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation stage	
The consideration received by Anadarko and its subsidiaries for the contribution of the assets and liabilities to us	5,725,431 common units; 26,536,306 subordinated units; 1,083,115 general partner units, and our IDRs.
Operational stage	
Distributions of available cash to our general partner, WGP and AMM	We will generally make cash distributions of 98.0% to our unitholders pro rata, including WGP and AMM as the holders of 49,296,205 common units and 449,129 common units, respectively, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% interest in us. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level.
Payments to our general partner and its affiliates	Our general partner and its affiliates are entitled to reimbursement for expenses incurred on our behalf, including salaries and employee benefit costs for employees who provide services to us, and all other necessary or appropriate expenses allocable to us or reasonably incurred by our general partner and its affiliates in connection with operating our business. The partnership agreement provides that our general partner determines in good faith the amount of such expenses that are allocable to us.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation stage	
Liquidation	Upon our liquidation, our partners, including our general partner, WGP and AMM, will be entitled to receive liquidating distributions according to their respective

capital account balances.

Agreements with Anadarko

We and other parties entered into various agreements with Anadarko in connection with our IPO in May 2008 and our acquisitions from Anadarko. These agreements address the acquisition of assets and the assumption of liabilities by us and our subsidiaries. These agreements were not the result of arm's-length negotiations and, as such, they or underlying transactions may not be based on terms as favorable as those that could have been obtained from unaffiliated third parties.

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Omnibus Agreement

In connection with our IPO, we entered into an omnibus agreement with Anadarko and our general partner that addresses the following matters:

- Anadarko's obligation to indemnify us for certain liabilities and our obligation to indemnify Anadarko for certain liabilities;
- our obligation to reimburse Anadarko for expenses incurred or payments made on our behalf in conjunction with Anadarko's provision of general and administrative services to us, including salary and benefits of Anadarko personnel, our public company expenses, general and administrative expenses and salaries and benefits of our executive management who are employees of Anadarko (see Administrative services and reimbursement below for details regarding certain agreements for amounts reimbursed in 2013); and
- our obligation to reimburse Anadarko for all insurance coverage expenses it incurs or payments it makes with respect to our assets.

The table below reflects the categories of expenses for which the Partnership was obligated to reimburse Anadarko pursuant to the omnibus agreement for the year ended December 31, 2013:

thousands	Year Ended December 31, 2013
Reimbursement of general and administrative expenses	$16,882
Reimbursement of public company expenses	7,152
Total reimbursement	$24,034

Any or all of the provisions of the omnibus agreement are terminable by Anadarko at its option if our general partner is removed without cause and units held by our general partner and its affiliates are not voted in favor of that removal. The omnibus agreement will also generally terminate in the event of a change of control of us or our general partner. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Administrative services and reimbursement. Under the omnibus agreement, we reimburse Anadarko for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit with respect to the assets Anadarko contributed to us concurrently with the closing of our May 2008 IPO, consisting of Anadarko Gathering Company LLC, Pinnacle Gas Treating LLC and MIGC LLC ("MIGC"), which we refer to as our "initial assets," and for subsequent acquisitions. The omnibus agreement further provides that we reimburse Anadarko for all expenses it incurs or payments it makes with respect to our assets.

Pursuant to these arrangements, Anadarko performs centralized corporate functions for us, 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. We reimburse Anadarko for expenses it incurs or payments it makes on our behalf, including salaries and benefits of Anadarko personnel, our public company expenses, our general and administrative expenses and salaries and benefits of our executive management who are also employees of Anadarko. Under the omnibus agreement, our reimbursement to Anadarko for general and administrative expenses it allocates to us is determined by Anadarko in its reasonable discretion.

Indemnification with respect to initial assets. Under the omnibus agreement, Anadarko agreed to indemnify us against certain environmental, title and operation matters associated with our initial assets. We have claimed no indemnities under the omnibus agreement prior to the date hereof. Other than with respect to certain tax liabilities attributable to assets or liabilities retained by Anadarko, the indemnification obligations under the omnibus agreement have expired.

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Indemnification Agreements with Directors and Officers

Our general partner entered into indemnification agreements with each of its officers and directors (each, an Indemnitee). Each indemnification agreement provides that our general partner will indemnify and hold harmless each Indemnitee against all expense, liability and loss (including attorney's fees, judgments, fines or penalties and amounts to be paid in settlement) actually and reasonably incurred or suffered by the Indemnitee in connection with serving in their capacity as officers and directors of our general partner (or of any subsidiary of our general partner) or in any capacity at the request of our general partner or its board of directors to the fullest extent permitted by applicable law, including Section 18-108 of the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. The indemnification agreements also provide that our general partner must advance payment of certain expenses to the Indemnitee, including fees of counsel, in advance of final disposition of any proceeding subject to receipt of an undertaking from the Indemnitee to return such advance if it is ultimately determined that the Indemnitee is not entitled to indemnification.
Through December 31, 2013, there have been no payments or claims to Anadarko related to indemnifications and no payments or claims have been received from Anadarko related to indemnifications.

Services and Secondment Agreement

In connection with our IPO, Anadarko and our general partner entered into a services and secondment agreement, pursuant to which specified employees of Anadarko are seconded to our general partner to provide operating, routine maintenance and other services with respect to the assets we own and operate under the direction, supervision and control of our general partner. Pursuant to the services and secondment agreement, our general partner 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.

Tax Sharing Agreement

In connection with our IPO, we entered into a tax sharing agreement pursuant to which we reimburse Anadarko for our estimated share of applicable state taxes. These taxes include income taxes attributable to our 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 our acquisition of the Partnership assets, which refers collectively to the assets acquired from Anadarko and owned by the Partnership as of December 31, 2013. Anadarko may use its own tax attributes to reduce or eliminate the tax liability of its combined or consolidated group, which may include us as a member. However, under this circumstance, we nevertheless are required to reimburse Anadarko for our allocable share of taxes that would have been owed had tax attributes not been available to Anadarko.

Related-Party Acquisition Agreements

Powder River. In November 2008, we and our subsidiaries entered into the Powder River contribution agreement with Anadarko and several of its affiliates pursuant to which we acquired the Powder River assets (which included the Hilight system, a 50% interest in the Newcastle system and a 14.81% limited liability company membership interest in Fort Union) from Anadarko. These assets provide a combination of gathering, processing, compressing and treating services in the Powder River Basin of Wyoming and are connected or adjacent to our MIGC pipeline. The consideration consisted of (i) $175.0 million in cash, which was financed by borrowing $175.0 million from Anadarko pursuant to the terms of a five-year term loan agreement, and (ii) the issuance of 2,556,891 of our common units and 52,181 of our general partner units. The acquisition closed on December 19, 2008.

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Chipeta. In July 2009, we and our subsidiaries entered into the Chipeta contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired a 51% membership interest in Chipeta Processing LLC ("Chipeta"), together with an associated NGL pipeline from Anadarko for (i) approximately $101.5 million in cash, which was financed by borrowing $101.5 million from Anadarko pursuant to the terms of a 7.0% fixed-rate, three-year term loan agreement, and (ii) the issuance of 351,424 of our common units and 7,172 of our general partner units. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah. The Chipeta processing complex includes three processing trains (one refrigeration and two cryogenic).
On August 1, 2012, we acquired Anadarko's then-remaining 24% membership interest in Chipeta, although we began receiving distributions related to the additional interest effective July 1, 2012, and Anadarko ceased to be a party to the Chipeta LLC agreement, as defined under the caption Chipeta LLC Agreement within this Item 13.

Granger. In January 2010, we and our subsidiaries entered into the Granger contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired the Granger assets from Anadarko for (i) approximately $241.7 million in cash, which was financed with $210.0 million of borrowings under the Partnership's revolving credit facility ("RCF") plus $31.7 million of cash on hand, and (ii) the issuance of 620,689 of our common units and 12,667 of our general partner units.

Wattenberg. In August 2010, we and our subsidiaries entered into the Wattenberg contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired certain midstream assets from Anadarko for (i) $473.1 million in cash consideration, which was funded through (a) $250.0 million borrowed under a term loan agreement, (b) $200.0 million borrowed under the Partnership's RCF, and (c) cash on hand, and (ii) the issuance of 1,048,196 of our common units and 21,392 of our general partner units.

White Cliffs. In September 2010, the Partnership and Anadarko closed a series of related transactions through which the Partnership acquired a 10% member interest in White Cliffs. Specifically, the Partnership acquired Anadarko's 100% ownership interest in Anadarko Wattenberg Company, LLC ("AWC") for $20.0 million in cash pursuant to a purchase and sale agreement. AWC owned a 0.4% interest in White Cliffs and held an option to increase its interest in White Cliffs. Also, in a series of concurrent transactions, AWC acquired an additional 9.6% interest in White Cliffs from a third party for $18.0 million in cash, subject to post-closing adjustments. As of December 31, 2013, the Partnership holds a 10% interest in White Cliffs and the remaining 90% is held by third parties.

Bison. In July 2011, we and our subsidiaries entered into the Bison contribution agreement with Anadarko and several of its affiliates. Pursuant to the agreement, we acquired certain midstream assets from Anadarko for (i) $25.0 million in cash consideration, which was funded through cash on hand, and (ii) the issuance of 2,950,284 of our common units and 60,210 of our general partner units.

Mountain Gas Resources, LLC. On January 13, 2012, the Partnership completed the acquisition of Anadarko's 100% ownership interest in Mountain Gas Resources, LLC ("MGR"), which owns the Red Desert complex, a 22% interest in Rendezvous and related facilities, effective January 1, 2012. The Red Desert complex includes the Patrick Draw processing plant, the Red Desert processing plant, 1,039 miles of gathering lines and related facilities. Rendezvous owns a 338-mile mainline gathering system serving the Jonah and Pinedale Anticline fields in southwestern Wyoming, which delivers gas to the Granger complex and other locations. The consideration paid consisted of the following: (i) $159.6 million of cash on hand, (ii) $299.0 million borrowings under the RCF, and (iii) the issuance of 632,783 common units and 12,914 general partner units.

Non-Operated Marcellus Interest. On March 1, 2013, the Partnership completed the acquisition of Anadarko's 33.75% interest (non-operated) in both the Liberty and Rome gas gathering systems. The interest acquired is referred to as the "Non-Operated Marcellus Interest." The assets in the Non-operated Marcellus Interest acquisition serve production from the Marcellus shale in north-central Pennsylvania. The consideration paid consisted of the following: (i) $215.5

million of cash on hand, (ii) $250.0 million borrowings under the RCF, and (iii) the issuance of 449,129 common units. In connection with the issuance of the common units, the general partner purchased 9,166 general partner units for consideration of $0.5 million in order to maintain its 2.0% general partner interest in the Partnership.

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Pursuant to the above related-party acquisition agreements, Anadarko has agreed to indemnify us and our respective affiliates (other than any of the entities controlled by Anadarko), shareholders, unitholders, members, directors, officers, employees, agents and representatives against certain losses resulting from any breach of Anadarko's representations, warranties, covenants or agreements, and for certain other matters. We have agreed to indemnify Anadarko and its respective affiliates (other than us and our respective security holders, officers, directors and employees) and their respective security holders, officers, directors and employees against certain losses resulting from any breach of our representations, warranties, covenants or agreements made in such agreements.
The board of directors of our general partner approved the acquisition of the Powder River assets, the Chipeta assets, the Granger assets, the Wattenberg assets, the Bison assets, Mountain Gas Resources, LLC, AWC, and the Non-Operated Marcellus Interest, based in part on the recommendations in favor of the acquisitions from, and the granting of special approval under our partnership agreement by, the board's special committee. The special committee, a committee of independent members of our general partner's board of directors, retains independent legal and financial advisors to assist it in evaluating and negotiating the acquisitions as it deems necessary on a transaction-by-transaction basis.

Subsequent Events

On February 27, 2014, the Partnership announced it agreed to acquire Anadarko's 20% interest in Texas Express Pipeline LLC and Texas Express Gathering LLC, and a 33.33% interest in Front Range Pipeline LLC (collectively, the "TEFR acquisition") for $375 million. The Partnership intends to finance the TEFR acquisition, which is expected to close on March 3, 2014, with $6.3 million of cash on hand, the borrowing of $350.0 million on the 2014 WES RCF, and the issuance of 308,490 common units to Anadarko at an implied price of approximately $60.78 per unit. In connection with the TEFR acquisition, our general partner and another wholly owned subsidiary of Anadarko will enter into an indemnification agreement (the "TEFR Indemnification Agreement") whereby such subsidiary will indemnify our general partner for any recourse liability it may have for 2014 RCF borrowings, or other debt financing, attributable to the TEFR acquisition. Our general partner and Western Gas Resources, Inc. ("WGRI") will also amend and restate the existing indemnity agreement between them (as discussed below) to reduce the amount for which WGRI would indemnify our general partner by an amount equal to any amounts payable to our general partner under the TEFR Indemnification Agreement. Our general partner and another wholly owned subsidiary of Anadarko will also amend and restate the 2013 Indemnification Agreement primarily to conform language among all the indemnity agreements with our general partner.
The Partnership also announced on February 27, 2014, that its board of directors appointed Jacqueline A. Dimpel as a Senior Vice President. Ms. Dimpel also serves as Anadarko's Vice President of Midstream, having succeeded Danny Rea upon his retirement at the end of 2013.

Chipeta LLC Agreement

In connection with the Partnership's acquisition of its initial 51% membership interest in Chipeta, as discussed above in Related-Party Acquisition Agreements, the Partnership became party to Chipeta's limited liability company agreement, as amended and restated as of July 23, 2009 (the "Chipeta LLC agreement"), together with Anadarko and a third-party member. Among other things, the Chipeta LLC agreement provides the following:

- Chipeta's members will be required from time to time to make capital contributions to Chipeta to the extent approved by the members in connection with Chipeta's annual budget;
- Chipeta will distribute available cash, as defined in the Chipeta LLC agreement, if any, to its members quarterly in accordance with those members' membership interests; and
- Chipeta's membership interests are subject to significant restrictions on transfer.

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Upon acquisition of our initial 51% membership interest in Chipeta, we became the managing member of Chipeta. As managing member, we manage the day-to-day operations of Chipeta and receive a management fee from the other members, which is intended to compensate the managing member for the performance of its duties. We may be removed as the managing member only if we are grossly negligent or fraudulent, breach our primary duties or fail to respond in a commercially reasonable manner to written business proposals from the other members, and such behavior, breach or failure has a material adverse effect to Chipeta. Effective August 1, 2012, we acquired Anadarko's then-remaining 24% membership interest in Chipeta, receiving distributions related to the additional interest beginning July 1, 2012, and Anadarko ceased to be a party to the Chipeta LLC agreement.

Note Receivable from and Amounts Payable to Anadarko

Concurrent with the closing of our May 2008 IPO, we 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.
In 2008, we entered into a five-year $175.0 million term loan agreement with Anadarko. The interest rate was fixed at 4.00% until November 2010. The term loan agreement was amended in December 2010 to fix the interest rate at 2.82% through maturity in 2013. During the year ended December 31, 2012, we incurred approximately $2.4 million in interest on the loan. In June 2012, the note payable to Anadarko was repaid in full with proceeds from the issuance of the 2022 Notes.
During the first quarter of 2012, the board of directors of our general partner approved the continued construction of the Brasada gas processing facility and Lancaster plant in South Texas and Northeast Colorado, respectively, which were previously under construction by Anadarko. We agreed to reimburse Anadarko for $18.9 million of certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada facility and Lancaster plant. In February 2012, these expenditures were transferred to us and a corresponding current payable was recorded, which we repaid during the fourth quarter of 2012.

Commodity Price Swap Agreements

We have commodity price swap agreements with Anadarko to mitigate exposure to 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 Granger, Hilight, Hugoton, Newcastle, MGR and Wattenberg assets, with various expiration dates through December 2016. In December 2013, we extended the commodity price swap agreements for the Hilight and Newcastle assets through December 2014. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Gas Gathering and Processing Agreements

We have significant gas gathering and processing arrangements with affiliates of Anadarko on a majority of our systems. The gathering agreements of our initial assets allow for rate resets that target an 18% return on invested capital in those assets. For the year ended December 31, 2013, 57% of our gathering, transportation and treating throughput and 56% of our processing throughput, was attributable to natural gas production owned or controlled by Anadarko, in each case exclusive of its equity investment throughput and volumes measured in barrels.

Gas Purchase and Sale Agreements

We sell substantially all of our natural gas, NGLs and condensate to Anadarko Energy Services Company ("AESC"), Anadarko's marketing affiliate. In addition, we purchase natural gas from AESC pursuant to gas purchase agreements. Our gas purchase and sale agreements with AESC are generally one-year contracts, subject to annual renewal.

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Equipment Purchases and Sales. The following table summarizes the purchases from and sales to Anadarko of pipe and equipment:

	Year Ended December 31,					
	2013	2012	2011	2013	2012	2011
thousands	Purchases			Sales		
Cash consideration	$11,211	$24,705	$3,837	$85	$760	$382
Net carrying value	5,309	8,009	1,998	38	393	316
Partners' capital adjustment	$5,902	$16,696	$1,839	$47	$367	$66

Contributions in aid of construction costs from affiliates.

During the fourth quarter of 2013, a subsidiary of Anadarko entered into an aid in construction agreement with us, whereby we will construct five receipt-point facilities at the Brasada facility that will serve the Anadarko subsidiary. Such subsidiary will reimburse us for costs associated with construction of the receipt points.

Indemnification Agreements

The 5.375% Senior Notes due 2021 (the "2021 Notes"), the 4.000% Senior Notes due 2022 (the "2022 Notes") and obligations under the RCF are recourse to our general partner. Our general partner is indemnified by a wholly owned subsidiary of Anadarko, WGRI, against any claims made against our general partner under the 2022 Notes, the 2021 Notes and/or the RCF.

In connection with the acquisition of the Non-Operated Marcellus Interest in March 2013, our general partner and another wholly owned subsidiary of Anadarko entered into the 2013 Indemnification Agreement whereby such subsidiary 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 or the Anadarko-Operated Marcellus Interest. The 2013 Indemnification Agreement applies to the $250.0 million of the 2.600% Senior Notes due 2018. Our general partner and WGRI also amended and restated the existing indemnity agreement between them to reduce the amount for which WGRI would indemnify our general partner by an amount equal to any amounts payable to our general partner under the 2013 Indemnification Agreement.

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Summary of Affiliate Transactions

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

The following table summarizes affiliate transactions (see Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K):

	Year ended December 31,		
thousands	2013	2012	2011
Revenues [1]	$829,258	$704,137	$658,680
Cost of product [1]	129,045	145,250	83,722
Operation and maintenance [2]	56,435	51,237	51,339
General and administrative [3]	23,354	92,847	33,305
Operating expenses	208,834	289,334	168,366
Interest income, net [4]	16,900	16,900	24,106
Interest expense [5]	—	2,766	4,935
Distributions to unitholders [6]	169,150	98,280	68,039
Contributions from noncontrolling interest owners [7]	—	12,588	16,476
Distributions to noncontrolling interest owners [7]	—	6,528	9,437

(1) Represents amounts 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 our assets, as well as expenses incurred by Anadarko on a historical basis related to our assets prior to the acquisition of such assets by us.

(3) Represents general and administrative expense incurred on and subsequent to the date of the acquisition of our assets, as well as a management services fee for reimbursement of expenses incurred by Anadarko for periods prior to the acquisition of our assets by us. These amounts include equity-based compensation expense allocated to us by Anadarko. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(4) Represents interest income recognized on the note receivable from Anadarko. For the year ended December 31, 2011, this line item also includes interest income, net on affiliate balances related to the Non-Operated Marcellus Interest, the MGR assets and the Bison assets for periods prior to the acquisition of such assets. Beginning December 7, 2011, Anadarko discontinued charging interest on intercompany balances. The outstanding affiliate balances on our assets prior to acquisition were entirely settled through an adjustment to net investment by Anadarko. See Note 10—Debt and Interest Expense in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(5) For the year ended December 31, 2012, includes interest expense recognized on the note payable to Anadarko and interest imputed on the reimbursement payable to Anadarko for certain expenditures Anadarko incurred in 2011 related to the construction of the Brasada facility and Lancaster plant. We repaid the note payable to Anadarko in June 2012, and repaid the reimbursement payable to Anadarko related to the construction of the Brasada facility and Lancaster plant in the fourth quarter of 2012. See Note 5—Transactions with Affiliates in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

(6) Represents distributions paid under the partnership agreement.

(7)

As described in the caption Chipeta LLC Agreement within this Item 13, we acquired Anadarko's then-remaining 24% membership interest in Chipeta 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.

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Other

In 2013, we and Anadarko made payments totaling approximately (a) $262,000 to affiliates of Crane Capital Holdings, Limited; and (b) $350,000 to the Houston Astros Baseball Club. James R. Crane, a member of the board of directors of our general partner, owns Crane Capital Holdings, Limited and is the Chairman and Chief Executive Officer of its management company, Crane Capital Group, Inc., and is the principal owner and Chairman of the Houston Astros.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates, including WGP and Anadarko, on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owner (WGP). At the same time, our general partner also has duties to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve the conflict. Our partnership agreement contains provisions that modify and limit our general partner’s default state law fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of fiduciary duties otherwise applicable under state law. See the caption Special Committee under Item 10 of this Form 10-K.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is any of the following:

- approved by the special committee of our general partner, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- 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.

Our general partner may, but is not required to, seek the approval of such resolution from the special committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the special committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points 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. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the special committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. Our partnership agreement provides that for someone to act in good faith, that person must reasonably believe he is acting in the best interests of the partnership.

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Item 14. Principal Accounting Fees and Services

We have engaged KPMG LLP as our independent registered public accounting firm. The following table presents fees for the audit of the Partnership’s annual consolidated financial statements for the last two fiscal years and for other services provided by KPMG LLP:

thousands	2013	2012
Audit fees	$1,031	$948
Audit-related fees	758	665
Total	$1,789	$1,613

Audit fees are primarily for the audit of the Partnership’s consolidated financial statements, including the audit of the effectiveness of the Partnership’s internal controls over financial reporting, and the reviews of the Partnership’s financial statements included in the Forms 10-Q.
Audit-related fees are primarily for other audits, consents, comfort letters and certain financial accounting consultation.

Audit Committee Approval of Audit and Non-Audit Services

The Audit Committee of the Partnership’s general partner has adopted a Pre-Approval Policy with respect to services that may be performed by KPMG LLP. This policy lists specific audit-related services as well as any other services that KPMG LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional Audit Committee authorization. The Audit Committee receives quarterly reports on the status of expenditures pursuant to that Pre-Approval Policy. The Audit Committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the Audit Committee or by its Chairperson, to whom such authority has been conditionally delegated, prior to engagement. During 2013, no fees for services outside the scope of audit, review, or attestation that exceed the waiver provisions of 17 CFR 210.2-01(c)(7)(i)(C) were approved by the Audit Committee.
The Audit Committee has approved the appointment of KPMG LLP as independent registered public accounting firm to conduct the audit of the Partnership’s consolidated financial statements for the year ended December 31, 2014.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)(1) Financial Statements

Our consolidated financial statements are included under Item 8 of this Form 10-K. For a listing of these statements and accompanying footnotes, please see the Index to Consolidated Financial Statements under Item 8 of this Form 10-K.

(a)(2) Financial Statement Schedules

Our supplemental quarterly information is included under Part II, Item 8 of this Form 10-K.

(a)(3) Exhibits

Exhibit Index

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

	Inc., Western Gas Partners, LP, Western Gas Operating, LLC and WGR Operating, LP. (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 15, 2011, File No. 001-34046).
2.8#	Contribution Agreement, dated as of February 27, 2013, by and among Anadarko Marcellus Midstream, L.L.C., Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, Anadarko Petroleum Corporation and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 2.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).

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Exhibit Number	Description
2.9*#	Contribution Agreement, dated as of February 27, 2014, by and among WGR Asset Holding Company, LLC, APC Midstream Holdings, LLC, Western Gas Partners, LP, Western Gas Operating, LLC, WGR Operating, LP, and Anadarko Petroleum Corporation.
3.1	Certificate of Limited Partnership of Western Gas Partners, LP (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.2	First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated May 14, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
3.3	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated December 19, 2008 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated as of April 15, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on April 20, 2009, File No. 001-34046).
3.5	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated July 22, 2009 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
3.6	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP dated January 29, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
3.7	Amendment No. 5 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 2, 2010 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
3.8	Amendment No. 6 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated July 8, 2011 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 8, 2011, File No. 001-34046).
3.9	Amendment No. 7 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated January 13, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 17, 2012, File No. 001-34046).
3.10	Amendment No. 8 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated August 1, 2012 (incorporated by reference to Exhibit 3.10 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on August 2, 2012, File No. 001-34046).
3.11	Amendment No. 9 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated December 12, 2012 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
3.12	Amendment No. 10 to First Amended and Restated Agreement of Limited Partnership of Western Gas Partners, LP, dated March 1, 2013 (incorporated by reference to Exhibit 3.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
3.13	Certificate of Formation of Western Gas Holdings, LLC (incorporated by reference to Exhibit 3.3 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on October 15, 2007, File No. 333-146700).
3.14	Second Amended and Restated Limited Liability Company Agreement of Western Gas Holdings, LLC, dated December 12, 2012 (incorporated by reference to Exhibit 3.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 12, 2012, File No. 001-34046).
4.1	Specimen Unit Certificate for the Common Units (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).

4.2	Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).

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Exhibit Number	Description
4.3	First Supplemental Indenture, dated as of May 18, 2011, among Western Gas Partners, LP, as Issuer, the Subsidiary Guarantors named therein, as Guarantors, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.4	Form of 5.375% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 18, 2011, File No. 001-34046).
4.5	Fifth Supplemental Indenture, dated as of August 14, 2013, among Western Gas Partners, LP, as Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
4.6	Form of 4.000% Senior Notes due 2022 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on June 28, 2012, File No. 001-34046).
4.7	Form of 2.600% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 14, 2013, File No. 001-34046).
10.1	Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC and Anadarko Petroleum Corporation, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.3 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.2	Amendment No. 1 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 19, 2008 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on December 24, 2008, File No. 001-34046).
10.3	Amendment No. 2 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of July 22, 2009 (incorporated by reference to Exhibit 10.2 to Western Gas Partners, LP's Current Report on Form 8-K filed on July 23, 2009, File No. 001-34046).
10.4	Amendment No. 3 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of December 31, 2009 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on January 7, 2010, File No. 001-34046).
10.5	Amendment No. 4 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of January 29, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on February 3, 2010, File No. 001-34046).
10.6	Amendment No. 5 to Omnibus Agreement by and among Western Gas Partners, LP, Western Gas Holdings, LLC, and Anadarko Petroleum Corporation, dated as of August 2, 2010 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on August 5, 2010, File No. 001-34046).
10.7	Services And Secondment Agreement between Western Gas Holdings, LLC and Anadarko Petroleum Corporation dated May 14, 2008 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.8	Tax Sharing Agreement by and among Anadarko Petroleum Corporation and Western Gas Partners, LP, dated as of May 14, 2008 (incorporated by reference to Exhibit 10.5 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.9	Anadarko Petroleum Corporation Fixed Rate Note due 2038 (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).

10.10	Form of Commodity Price Swap Agreement (filed as Exhibit 10.3 to the Partnership's Form 10-Q for the quarter ended March 31, 2010).
10.11‡	Form of Indemnification Agreement by and between Western Gas Holdings, LLC, its Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 2 to Western Gas Partners, LP's Registration Statement on Form S-1 filed on January 23, 2008, File No. 333-146700).
10.12‡	Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on June 13, 2008, File No. 001-34046).

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Exhibit Number	Description
10.13‡	Form of Award Agreement under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Western Gas Partners, LP's Current Report on Form 8-K filed on May 14, 2008, File No. 001-34046).
10.14†	Amended and Restated Limited Liability Company Agreement of Chipeta Processing LLC effective July 23, 2009 (incorporated by reference to Exhibit 10.4 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on November 12, 2009, File No. 001-34046).
10.15*	Second Amended and Restated Revolving Credit Agreement, dated as of February 26, 2014, among Western Gas Partners, LP, Wells Fargo Bank National Association, as the administrative agent and the lenders party thereto.
10.16	Indemnification Agreement, dated March 1, 2013, between Western Gas Holdings, LLC and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
10.17	Third Amended and Restated Indemnification Agreement, dated March 1, 2013, between Western Gas Holdings, LLC and Western Gas Resources, Inc. (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Current Report on Form 8-K filed on March 5, 2013, File No. 001-34046).
10.18	Assignment of Indemnification Agreement, dated April 1, 2013, between Anadarko USH2 LLC and Anadarko E&P Onshore LLC (incorporated by reference to Exhibit 10.1 to Western Gas Partners, LP's Quarterly Report on Form 10-Q filed on August 1, 2013, File No. 001-34046).
12.1*	Ratio of Earnings to Fixed Charges.
21.1*	List of Subsidiaries of Western Gas Partners, LP.
23.1*	Consent of KPMG LLP.
31.1*	Certification of Chief Executive Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer, pursuant to Rule 13a-14(a)/15d-14(a), as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

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*	Filed herewith
**	Furnished herewith
#	Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted schedule to the Securities and Exchange Commission upon request.
†	Portions of this exhibit, which was previously filed with the Securities and Exchange Commission, were omitted pursuant to a request for confidential treatment. The omitted portions were filed separately with the Securities and Exchange Commission.
‡	Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN GAS PARTNERS, LP

February 28, 2014

/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)

Each person whose signature appears below constitutes and appoints Donald R. Sinclair and Benjamin M. Fink, and each of them, either one of whom may act without joinder of the other, his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any or all amendments to this Form 10-K, and to file the same, with all, exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each, and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, and each of them, or the substitute or substitutes of any or all of them, may lawfully do or cause to be done by virtue hereof.

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2014.

Signature	Title (Position with Western Gas Holdings, LLC)
/s/ Robert G. Gwin Robert G. Gwin	Chairman and Director
/s/ Donald R. Sinclair Donald R. Sinclair	President, Chief Executive Officer and Director
/s/ Benjamin M Fink Benjamin M Fink	Senior Vice President, Chief Financial Officer and Treasurer
/s/ Charles A. Meloy Charles A. Meloy	Director
/s/ Robert K. Reeves Robert K. Reeves	Director
/s/ Steven D. Arnold Steven D. Arnold	Director
/s/ Milton Carroll Milton Carroll	Director
/s/ James R. Crane James R. Crane	Director
/s/ David J. Tudor David J. Tudor	Director