Western Gas Partners LP
Form 10-K
February 28, 2012
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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, 2011

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)

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. þ

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 ¨ Smaller reporting company ¨

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

The aggregate market value of the Partnership s common units representing limited partner interests held by non-affiliates of the registrant was approximately $1.5 billion on June 30, 2011, based on the closing price as reported on the New York Stock Exchange.

At February 23, 2012, there were 90,773,782 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.

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.

CO_2: Carbon dioxide.

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

Cryogenic: The fractionation 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.

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.

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Long ton: A British unit of weight equivalent to 2,240 pounds.

LTD: Long tons per day.

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.

Pounds per square inch, absolute: The pressure resulting from a one-pound force applied to an area of one square inch, including local atmospheric pressure. All volumes presented herein are based on a standard pressure base of 14.73 pounds per square inch, absolute.

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 gas: The natural gas remaining after being processed or treated.

Sour gas: Natural gas containing more than four parts per million of hydrogen sulfide.

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 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 and are listed on the New York Stock Exchange under the symbol WES.

The Partnership s general partner is Western Gas Holdings, LLC (the general partner or GP), a wholly owned subsidiary of Anadarko Petroleum Corporation. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union Gas Gathering, LLC (Fort Union) and White Cliffs Pipeline, LLC (White Cliffs). Anadarko Petroleum Corporation refers to Anadarko Petroleum Corporation excluding its subsidiaries and affiliates. AGC refers to Anadarko Gathering Company LLC, PGT refers to Pinnacle Gas Treating LLC, 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 file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents electronically 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 site located at *www.westerngas.com/Investor/Pages/SECFilings.aspx*. 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, 2011, our assets consist of eleven gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline that is regulated by the Federal Energy Regulatory Commission (FERC), and interests in Fort Union and White Cliffs, which are accounted for under the equity method. Our assets are located in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming), and the Mid-Continent (Kansas and Oklahoma). The following table provides information regarding our assets by geographic region as of and for the year ended December 31, 2011:

Area	Asset Type	Miles of Pipeline	Approximate Number of Receipt Points	Gas Compression (Horsepower)	Processing or Treating Capacity (MMcf/d)	Average Gathering, Processing and Transportation Throughput (MMcf/d)
Rocky Mountains [1]	Gathering, Processing and Treating	5,379	4,432	265,679	2,077	1,672
	Transportation	782	12	26,828		93
Mid-Continent	Gathering	1,953	1,525	92,097		93
East Texas	Gathering and Treating	589	817	37,515	502	272
West Texas	Gathering	118	86			69
Total		8,821	6,872	422,119	2,579	2,199

(1) Throughput includes 100% of Chipeta system volumes, 50% of Newcastle system volumes and 14.81% of Fort Union s volumes. For the year ended December 31, 2011, throughput excludes 24 MBbls/d of average NGL pipeline volumes from the Chipeta assets and 4 MBbls/d of oil pipeline volumes representing our 10% share of average White Cliffs pipeline 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.

ACQUISITIONS

Acquisitions. The following table presents our acquisitions completed during 2011 and details the funding for those acquisitions through borrowings, cash on hand and/or the issuance of equity:

thousands except unit and percent amounts	Acquisition Date	Percentage Acquired	Borrowings	Cash On Hand	Common Units Issued	GP Units Issued
Platte Valley [1]	**02/28/11**	**100%**	**$ 303,000**	**$ 602**		
Bison [2]	**07/08/11**	**100%**		**25,000**	**2,950,284**	**60,210**

(1) The assets acquired from a third party include (i) a processing plant with initial cryogenic capacity of 84 MMcf/d, (ii) two fractionation trains, (iii) an initial 1,098-mile natural gas gathering system that delivers gas to the Platte Valley plant, either directly or through our Wattenberg gathering system, and (iv) related equipment. These assets, located in the Denver-Julesburg Basin, are referred to collectively as the Platte Valley assets or Platte Valley system and the acquisition as the Platte Valley acquisition. In connection with the acquisition, we

entered into long-term fee-based agreements with the seller to gather and process its existing gas production, as well as to expand the existing gathering systems and processing capacity. We financed the Platte Valley acquisition with borrowings under our revolving credit facility. See *Note 2. Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) The Bison gas treating facility that we acquired from Anadarko is located in the Powder River Basin in northeastern Wyoming, and includes (i) three amine treating units with a combined CO_2 treating capacity of 450 MMcf/d, (ii) three compressor units with combined compression of 5,230 horsepower, and (iii) five generators with combined power output of 6.5 megawatts. These assets are referred to collectively as the Bison assets and the acquisition as the Bison acquisition. The Bison assets are the only treating and delivery point into the third-party owned Bison pipeline. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010.

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Presentation of Partnership assets. References to the Partnership assets refer collectively to the assets owned by the Partnership as of December 31, 2011. Because of Anadarko s control of the Partnership through its ownership of our general partner, each acquisition of Partnership assets through December 31, 2011, except for the acquisitions of the Platte Valley assets and the 9.6% interest in White Cliffs from third parties, was considered a transfer of net assets between entities under common control (see *Note 2. Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K). As a result, after each acquisition of assets from Anadarko, we are required to revise our financial statements to include the activities of the Partnership assets as of the date of common control. As such, our historical financial statements previously filed with the SEC have been recast in this Form 10-K to include the results attributable to the Bison assets as if we owned such assets for all periods presented. The consolidated financial statements for periods prior to our acquisition of the Partnership assets 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.

EQUITY OFFERINGS

Equity offerings. We completed the following public equity offerings during 2011:

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**

(1) Includes the issuance of 302,813 common units and 750,000 common units pursuant to the exercise, in full or in part, of the underwriters over-allotment options granted in connection with the March 2011 and September 2011 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% interest.

STRATEGY

Our primary business objective is to continue to increase our cash distributions per unit over time. We intend to accomplish this objective by executing the following strategy:

Pursuing accretive acquisitions. We expect to continue to pursue accretive acquisition opportunities 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.

Attracting third-party volumes to our systems. We expect to continue actively marketing our midstream services to, and pursuing strategic relationships with, third-party producers 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. As of December 31, 2011, approximately 72% of our gross margin was generated under long-term contracts with fee-based rates, with the remainder provided under percent-of-proceeds and keep-whole contracts. We have entered into fixed-price swap agreements with Anadarko to manage the commodity price risk otherwise inherent in our percent-of-proceeds and keep-whole contracts. A substantial part of our business is conducted under long-term contracts with Anadarko.

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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 pursue projects that 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 long-term nature of our fee-based agreements and (ii) fixed-price swap agreements that limit our exposure to commodity price changes with respect to our percent-of-proceeds and keep-whole contracts.

- ***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 necessary to execute our strategy across capital-market cycles. See *Note 4. Equity and Partners Capital* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

- ***Substantial presence in liquids-rich basins.*** Our asset portfolio includes gathering and processing systems, such as our Wattenberg, Platte Valley, Chipeta and Granger assets, which are in areas where the hydrocarbon production contains a significant amount of liquids, for which pricing is correlated to crude oil as opposed to natural gas. See *Properties* below for further descriptions of these assets. 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. Drilling activity in liquids-rich areas is therefore less likely to decline in the current pricing environment than activity in relatively dryer gas areas, offering expansion opportunities for certain of our systems as producers attempt to increase their NGL production.

- ***Well-positioned, well-maintained and efficient assets.*** We believe that our asset portfolio across diverse areas of operation provides us with opportunities to expand and attract additional volumes to our systems. Moreover, our systems include high-quality, well-maintained assets for which we have implemented modern processing, treating, measuring and operating technologies.

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 one of Anadarko s wholly owned subsidiaries. Anadarko Petroleum Corporation 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. Over 73% of our total natural gas gathering, processing and transportation throughput during the year ended December 31, 2011 was comprised of natural gas production owned or controlled by Anadarko. In addition and solely with respect to the gathering systems owned by AGC, PGT and MIGC, which we refer to as our initial assets, and the Wattenberg gathering system, 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 these 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. We expect to utilize the experience of Anadarko s management team to execute our growth strategy, which includes acquiring and constructing additional midstream assets.

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As of December 31, 2011, Anadarko held 1,839,613 general partner units representing a 2.0% general partner interest in the Partnership, 39,789,221 common units representing a 43.3% limited partner interest, and 100% of the Partnership s incentive distribution rights (IDRs). The public held 50,351,778 common units, representing a 54.7% interest in the Partnership.

In connection with our initial public offering, 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 market, it is also a source of potential conflicts. For example, Anadarko is not restricted from competing with us. Given Anadarko s significant ownership, we believe it will be in Anadarko s best 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.

INDUSTRY OVERVIEW

The midstream natural gas industry is the link between the exploration and production of natural gas and the delivery of its 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.

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.

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Treating and dehydration. To the extent that gathered natural gas contains contaminants, such as water vapor, CO_2 and/or hydrogen sulfide, such natural gas is dehydrated to remove the saturated water and treated to separate the CO_2 and hydrogen sulfide from the gas stream.

Processing. Processing removes the heavier and more valuable hydrocarbon components, which are extracted as NGLs. The residue gas remaining after extraction of NGLs meets the quality standards for long-haul pipeline transportation or commercial use.

Fractionation. Fractionation is the separation of the mixture of extracted NGLs into individual components for end-use sale. It is accomplished by controlling the temperature and pressure of the stream of mixed NGLs in order to take advantage of the different boiling points of separate products.

Storage, transportation and marketing. Once the raw natural gas has been treated or processed and the raw NGLs 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 gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and/or NGLs.

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

Forms of transportation contracts. 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 amounts 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 natural gas, NGLs or crude oil 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, 2011:

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Rocky Mountains

Bison treating facility. The Bison treating facility consists of three amine treaters with a combined treating capacity of 450 MMcf/d located in the northeastern corner of Wyoming. 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 CO_2 treating services for the 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 approximately 73% of the throughput at the Bison treating facility for the year ended December 31, 2011. 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. 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 Ft. Union and Thunder Creek pipelines.

Chipeta. We are the managing member of Chipeta, a limited liability company owned by the Partnership (51%), Ute Energy Midstream Holdings LLC (25%) and Anadarko (24%). The Chipeta complex includes a natural gas processing plant with two processing trains, the Natural Buttes plant, and a 100% Partnership-owned 17-mile NGL pipeline connecting the Chipeta plant to a third-party pipeline. The Chipeta assets currently have cryogenic and refrigeration processing capacity of 670 MMcf/d. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah. In 2011, Chipeta began construction of a second cryogenic train at the Chipeta plant with processing capacity of approximately 300 MMcf/d that we expect to place in service in the third quarter of 2012.

Customers. Anadarko is the largest customer on the Chipeta system with approximately 94% of the system throughput for the year ended December 31, 2011. The balance of throughput on the system during 2011 was from three third-party customers.

Supply. The Chipeta system is well-positioned to access Anadarko and third-party production in the area with excess available capacity in the Uintah Basin. Anadarko controls approximately 217,000 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 through our 17-mile pipeline to the Mid-America Pipeline (MAPL), which provides transportation through the Seminole pipeline 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:

- Colorado Interstate Gas Company (CIG);
- Questar Pipeline Company s pipeline; and
- Wyoming Interstate Company, Ltd.

Clawson gathering system. The 47-mile Clawson gathering system, located in Carbon and Emery Counties of Utah, was built in 2001 to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal play. The Clawson gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas. The Clawson gathering system includes one compressor station, with 6,310 horsepower, and a CO_2 treating facility.

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Customers. Anadarko is the largest shipper on the Clawson gathering system with approximately 97% of the total throughput delivered into the system during the year ended December 31, 2011. The remaining throughput on the system was from one third-party producer.

Supply. Clawson Springs Field has approximately 7,000 gross acres and produces primarily from the Ferron Coal play.

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

Fort Union gathering system. The Fort Union system is a 324-mile 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 pipelines and includes CO_2 treating facilities at the Medicine Bow plant. The system s gas treating capacity will vary depending upon the CO_2 content of the inlet gas. At current CO_2 levels, the system is capable of treating and blending over 1 Bcf/d while satisfying the CO_2 specifications of downstream pipelines.

Fort Union Gas Gathering, LLC is a partnership among Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River LLC (37.04%), Bargath, Inc. (11.11%) and the Partnership (14.81%). Anadarko is the field and construction operator of the Fort Union gathering system.

Customers. The four Fort Union owners named above are the only firm shippers on the Fort Union system. To the extent capacity on the system is not used by the owners, 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 owners throughout the Powder River Basin. As of December 31, 2011, the Fort Union system produces gas from approximately 8,700 coal-bed methane wells in the expanding Big George coal play, the multiple seam coal fairway to the north of the Big George play and in the Wyodak coal play. Anadarko has a working interest in over 1.7 million gross acres within the Powder River Basin as of December 31, 2011. 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. Fort Union s throughput volumes decreased during 2011 due to the commencement of operations of TransCanada s Bison pipeline in January 2011.

Delivery points. The Fort Union system delivers coal-bed methane gas to the Glenrock, Wyoming Hub, which accesses the following interstate pipelines:

- 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.

Granger gathering system and processing plant. The 810-mile natural gas gathering system and gas processing facility is located in Sweetwater County, Wyoming. The Granger system includes eight field compression stations with 41,950 horsepower. The processing facility has a cryogenic capacity of 200 MMcf/d and refrigeration capacity of 100 MMcf/d with NGL fractionation.

Customers. Anadarko is the largest customer on the Granger system with approximately 54% of throughput for the year ended December 31, 2011. The remaining throughput was primarily from five third-party shippers.

Supply. The Granger system is supplied by the Moxa Arch, the Jonah field and the Pinedale anticline across which Anadarko controls approximately 568,000 gross acres. The Granger gas gathering system has approximately 690 receipt points.

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

- CIG;
- Kern River and Mountain Gas Transportation, Inc (MGTI) pipelines via a connect with Rendezvous Pipeline Company, a FERC-regulated Questar affiliate;
- Northwest Pipeline Co (NWPL);
- Overthrust Pipeline OTTCO; and
- Questar Gas Management Company (QGM).

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

Helper gathering system. The 67-mile Helper gathering system, located in Carbon County, Utah, was built to provide gathering services for Anadarko s coal-bed methane development of the Ferron Coal play. The Helper gathering system provides gathering, dehydration, compression and treating services for coal-bed methane gas. The Helper gathering system includes two compressor stations with a combined 14,075 horsepower and two CO_2 treating facilities.

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

Supply. The Helper Field and 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 approximately 19,000 acres as of December 31, 2011 and Cardinal Draw Field, which lies immediately to the east of Helper Field, also covers approximately 20,000 acres.

Delivery points. The Helper gathering system delivers into the 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.

Hilight gathering system and processing plant. The 1,056-mile Hilight gathering system, located in Johnson, Campbell, Natrona and Converse Counties of Wyoming, was built to provide low and high-pressure gathering services for the area s conventional gas production and delivers to the Hilight plant for processing. The Hilight gathering system has 11 compressor stations with 32,263 combined horsepower. The Hilight system has a capacity of approximately 30 MMcf/d and 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 from numerous third-party customers, with the nine largest producers providing approximately 75% of the system throughput during 2011.

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 gas into our MIGC transmission line. Hilight is not connected to an active NGL pipeline, so all fractionated NGLs are sold locally through its truck and rail loading facilities.

MIGC transportation system. The MIGC system is a 256-mile interstate pipeline regulated by 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.

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Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 86% of throughput for the year ended December 31, 2011, with the remaining throughput from 11 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 agreements range in term from approximately one to seven years. Of the current certificated capacity of 175 MMcf/d, 45 MMcf/d is contracted through September 2012 and 40 MMcf/d is contracted through October 2018. In addition to its certificated forward-haul capacity, MIGC provides firm backhaul service subject to flowing capacity. We have 12 MMcf/d contracted through May 2012 under backhaul service agreements that are renegotiated on an annual basis. Most of our 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. Due to the commencement of operations of TransCanada s Bison pipeline in January 2011, the existing firm transportation contracts that expired at the end of January 2011 were not renewed. 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, 2011, Anadarko has a working interest in over 1.7 million gross acres within the Powder River Basin. Anadarko s gross acreage includes substantial undeveloped acreage positions in the expanding Big George coal play and the multiple seam coal fairway to the north of the Big George play.

Delivery points. MIGC volumes can be redelivered to the Glenrock, Wyoming Hub, which accesses the following interstate pipelines:

- CIG;
- Kinder Morgan Interstate Gas Transportation Company;
- Williston Basin Interstate Pipeline Company; and
- Wyoming Interstate Gas Company.

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

Newcastle gathering system and processing plant. The 179-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 approximately 2 MMcf/d. The plant utilizes a refrigeration process and provides for fractionation of the recovered NGLs into propane and butane/gasoline mix products. The Newcastle facility is a joint venture among Black Hills Exploration and Production, Inc. (44.7%), John Paulson (5.3%) and the Partnership (50.0%). The Newcastle gathering system includes one 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 12 third-party customers, with the largest four producers providing approximately 92% of the system throughput during 2011. The largest producer, Black Hills Exploration, provided approximately 62% of the throughput during 2011.

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 gas from the Newcastle system is delivered into Anadarko s MGTC pipeline for transport, distribution and sale.

Platte Valley gathering system and processing plant. The Platte Valley system, located in the Denver-Julesburg Basin, consists of a processing plant with current cryogenic capacity of 100 MMcf/d, two fractionation trains, a 1,099-mile natural gas gathering system and related equipment. The Platte Valley gathering system has 13 compressor stations with a combined 17,011 of operating horsepower.

Customers. For the year ended December 31, 2011, approximately 8% of the Platte Valley system throughput was from Anadarko and the remaining throughput was from various third-party customers, the largest being EnCana Corporation.

Supply and delivery points. There are 713 receipt points connected to the Platte Valley gathering system as of December 31, 2011. The system is connected to our Wattenberg gathering system, as described below. The Platte Valley system 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 through the following pipelines:

- local markets;
- ONEOK Overland Pass Pipeline; and
- the Wattenberg Pipeline owned and operated by DCP Midstream (formerly the Buckeye Pipeline).

In addition, the Platte Valley system can deliver to the CIG and Xcel Energy residue gas pipelines.

Wattenberg gathering system and processing plant. The Wattenberg gathering system is a 1,781-mile wet gas gathering system in the Denver-Julesburg Basin, north and east of Denver, Colorado, and includes six compressor stations and combined 72,579 of operating horsepower. The Fort Lupton processing plant has two trains with combined processing capacity of 105 MMcf/d.

Customers. Anadarko-operated production represented approximately 66% of system throughput during the year ended December 31, 2011. Approximately 29% of Wattenberg system throughput was from two third-party producers and the remaining throughput was from various third-party customers.

Supply. There are 2,129 receipt points and over 5,900 wells connected to the gathering system as of December 31, 2011. The Wattenberg gathering system is primarily supplied by the Wattenberg field and covers portions of Adams, Arapahoe, Boulder, Broomfield and Weld counties. Anadarko controls approximately 762,000 gross acres in the Wattenberg field. Anadarko drilled 472 wells and completed 2,090 fracs in connection with its active recompletion and re-frac program at the Wattenberg field during 2011 and has identified 1,200 to 2,700 opportunities to increase production including new well locations, re-fracs and recompletions.

Delivery points. The Wattenberg gathering system has five delivery points, with 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 to DCP Midstream s Spindle processing plant and AKA Energy s Gilcrest processing plant. All delivery points are connected to CIG and Xcel Energy residue gas pipelines, the ONEOK Overland Pass Pipeline for NGLs, and also have truck-loading facilities for access to local NGL markets. Anadarko s Wattenberg and our Platte Valley processing plants also have NGL connections to the Wattenberg Pipeline owned and operated by DCP Midstream (formerly the Buckeye Pipeline).

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White Cliffs pipeline. The White Cliffs pipeline consists of a 526-mile crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma. It has an approximate capacity of 80,000 barrels per day. At the point of origin, it has a 100,000-barrel storage facility and a truck-loading facility with an additional 220,000 barrels of storage. The pipeline is a joint venture owned by SemCrude Pipeline LP (51%), Plains Pipeline LP (34%), Noble Energy, Inc. (5%) and the Partnership (10%).

Customers. The White Cliffs pipeline has two throughput contracts with Anadarko and Noble Energy that run through May 2014. In addition, other parties may ship on White Cliffs Pipeline at FERC-based rates. During the year ended December 31, 2011, Anadarko was the largest shipper on the White Cliffs pipeline.

Supply. The White Cliffs pipeline is supplied by production from the Denver-Julesburg Basin and is the only direct route from the Denver-Julesburg 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 the mid-continent refineries.

Mid-Continent

Hugoton gathering system. The 1,953-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 a combined 92,097 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with approximately 76% of the system throughput during the year ended December 31, 2011. Approximately 19% of the throughput on the Hugoton system for the year ended December 31, 2011 was from one third-party shipper with the balance from various other third-party shippers.

Supply. The Hugoton field is one of the largest natural gas fields in North America. The Hugoton field continues to be a long-life, slow-decline asset for Anadarko, which has an extensive acreage position in the field with approximately 470,000 gross acres. By virtue of a farm-out agreement between a third-party producer and Anadarko, the third-party producer gained the right to explore below the primary formations in the Hugoton field. Our existing asset is well-positioned to gather volumes that may be produced from successful new wells the third-party producer may drill.

Delivery points. The Hugoton gathering system is connected to DCP Midstream s National Helium plant, which extracts NGLs and helium and delivers residue gas into the Panhandle Eastern pipeline. The system is also connected to the Satanta plant, which is owned by Pioneer Natural Resources Corporation (51%) and Anadarko (49%), for NGLs and helium processing and delivers residue gas into Kansas Gas Services and Southern Star pipeline.

East Texas

Dew gathering system. The 323-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 10 compressor stations with a combined 36,175 horsepower of compression.

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

Supply. As of December 31, 2011, Anadarko has approximately 833 producing wells in the Bossier play and controls approximately 122,000 gross acres in the area.

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

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Pinnacle gathering system. The Pinnacle gathering system includes our 266-mile Pinnacle gathering system and our Bethel treating plant. The Pinnacle system provides sour gas gathering and treating service in Anderson, Freestone, Leon, Limestone and Robertson Counties of East Texas. The Bethel treating plant, located in Anderson County, has total CO_2 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 approximately 90% of system throughput for the year ended December 31, 2011. The remaining throughput on the system during 2011 was from four third-party shippers.

Supply. The Pinnacle gathering system is well-positioned to provide gathering and treating services to the five-county area over which it extends, including the Cotton Valley Lime formations, which contain relatively high concentrations of sulfur and CO_2. Total installed sulfur treating capacity is 20 LTD and we believe that we are well positioned to benefit from future sour gas production in the area.

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 s pipeline;
- ETC Texas Pipeline, Ltd pipeline; and
- Kinder Morgan s Tejas pipeline.

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

West Texas

Haley gathering system. The 118-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 approximately 69% of the Haley gathering system s throughput for the year ended December 31, 2011. The remaining throughput is attributable to Anadarko s partner in the Haley area.

Supply. In the greater Delaware basin, Anadarko has access to approximately 355,000 gross acres as of December 31, 2011, 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.

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COMPETITION

Competition on gathering systems and at processing plants. 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 our initial assets gathering systems and the Wattenberg gathering system. We believe our assets that are outside of the dedicated areas are geographically well positioned to retain and attract third-party volumes.

We believe the primary advantages of our assets are their proximity to established and/or new production, and our ability to provide flexible services 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.

The following table summarizes the primary competitors for our gathering systems and processing plants at December 31, 2011.

System	Competitor(s)
Bison assets	None
Chipeta processing plant	QEP Field Services Company and El Paso Midstream Group, Inc.
Clawson gathering systems	XTO Energy
Dew and Pinnacle gathering systems	ETC Texas Pipeline, Ltd; Enbridge Pipelines (East Texas) LP; XTO Energy; and Kinder Morgan Tejas Pipeline, LP
Fort Union gathering system	MIGC, Thunder Creek Gas Services, Williston Basin Interstate Pipeline Company and TransCanada
Granger gathering system and processing plant	Williams Field Services; Enterprise Gas Processing, LLC; Jonah Gas Gathering Company; and QEP Field Services Company
Haley gathering system	Anadarko s Delaware Basin JV Gathering LLC; Enterprise GC, LP; Targa Midstream Services LLC and Southern Union Energy Services Company
Helper gathering systems	None
Hilight gathering system and processing plant	DCP Midstream and Merit Energy
Hugoton gathering system	ONEOK Gas Gathering Company, DCP Midstream and Pioneer Natural Resources
Newcastle gathering system and processing plant	DCP Midstream
Platte Valley gathering system and processing plant	DCP Midstream and AKA Energy
Wattenberg gathering system and processing plant	DCP Midstream and AKA Energy

Competition on transportation systems. 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, pipeline interconnections, and gas quality. MIGC s major competitors are Thunder Creek Gas Services, TransCanada s Bison pipeline (which commenced operations in January 2011), Williston Basin Interstate Pipeline Company and the Fort Union gathering system. The White Cliffs pipeline faces no direct competition from other pipelines, although shippers could sell crude oil in local markets rather than ship to Cushing, Oklahoma. The 17-mile NGL line originating in Chipeta faces no direct competition.

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SAFETY AND MAINTENANCE

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 (DOT), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA) with respect to natural gas, and Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA) with respect to NGLs. Both the NGPSA and the HLPSA have been amended by the Pipeline Safety Improvement Act of 2002 (PSIA), which was reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas and NGL pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. hazardous liquid and natural gas transportation pipelines and some gathering lines in high-population areas.

These pipeline safety laws are subject to further amendment, with the potential for more onerous obligations and stringent standards being imposed on pipeline owners and operators. For example, on January 3, 2012, 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 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, and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas, and increases the maximum penalty for violation of pipeline safety regulations from $1.0 million to $2.0 million. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act 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.

The PHMSA has developed regulations implementing the PSIA that require transportation pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, (i) revising the definitions of high consequence areas and gathering lines ; (ii) strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed; (iii) strengthening requirements on the types of gas transmission pipeline integrity assessment methods that may be selected for use by operators; (iv) imposing gas transmission integrity management requirements on onshore gas gathering lines; (v) requiring the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; and (vi) enhancing the current requirements for internal corrosion control of gathering lines.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT 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 in complying with applicable state laws and regulations. Our pipelines have operations and maintenance plans designed to keep the facilities in compliance with pipeline safety requirements.

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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 U.S. Environmental Protection Agency s (EPA) community right-to-know regulations 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 material compliance with all applicable laws and regulations relating to worker health and safety.

REGULATION OF OPERATIONS

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Interstate transportation pipeline regulation. MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the Natural Gas Act of 1938 (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;
- the types of services MIGC may offer to its customers;
- 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;
- the initiation and discontinuation of services;
- market manipulation in connection with interstate sales, purchases or transportation of natural gas and NGLs; and
- participation by interstate pipelines in cash management arrangements.

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

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The rates and terms and conditions for our interstate pipeline services are set forth in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint or by action of the FERC under Section 5 of the NGA, and proposed rate increases may be challenged by protest. In November 2011, the FERC initiated an investigation to examine the justness and reasonableness of MIGC s rates pursuant to Section 5 of the NGA and set the matter for hearing. The outcome of the FERC s Section 5 case, or any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service on the MIGC system, but management does not believe the outcome of the MIGC Section 5 rate case will have a material effect on the Partnership s financial condition, results of operations or cash flows.

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.

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 new policy statement. On December 16, 2005, FERC issued its first significant case-specific review of the income tax allowance issue in a pipeline partnership s rate case. FERC reaffirmed its new income tax allowance policy and directed the subject pipeline to provide certain evidence necessary for the pipeline to determine its income tax allowance. The new tax allowance policy and the December 16, 2005 order were appealed to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit). The D.C. Circuit issued an order on May 29, 2007 in which it denied these appeals and upheld FERC s new tax allowance policy and the application of that policy in the December 16, 2005 order 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 MLPs 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 (EPAct 2005). Among other matters, 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 to be 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 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 such 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.

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The new anti-manipulation rules apply to interstate gas pipelines and storage companies and intrastate gas pipelines and storage companies that provide interstate services, such as Section 311 service, 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. 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.

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.

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 720, as clarified by orders on clarification and rehearing, was vacated by the United States Court of Appeals for the Fifth Circuit (Fifth Circuit) with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order 720, as clarified, remained applicable to interstate pipelines with respect to the additional posting requirements. On May 20, 2010, the 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 the Commission s periodic review of the rates charged by the subject pipelines from three years to five years. The 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 the 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, the Commission issued Order No. 735-A, which generally reaffirmed Order No. 735, with certain modifications. On January 19, 2012, the Commission issued Order No. 757, which eliminates the semi-annual storage reporting requirements for interstate pipelines and section 311 and Hinshaw pipelines as largely duplicative with other reporting requirements.

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. 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. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, is the subject of substantial, on-going 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. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, 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.

During the 2007 legislative session, the Texas State Legislature passed House Bill 3273 (Competition Bill) and House Bill 1920 (LUG Bill). The Texas Competition Bill and LUG Bill contain provisions applicable to gathering facilities. The Competition Bill allows the Railroad Commission of Texas (TRRC), the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering in formal rate proceedings. It also gives the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters and gatherers for taking discriminatory actions against shippers and sellers. The LUG Bill modifies the informal complaint process at the TRRC with procedures unique to lost and unaccounted for gas issues. It extends the types of information that can be requested and gives the TRRC the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. We cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on our gathering operations.

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. 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 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 2011 Pipeline Safety Act also imposes new notification and reporting requirements. Many specific requirements will be developed as part of future regulations. While we cannot predict how DOT will implement the 2011 Pipeline Safety 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.

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Financial reform legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), signed into law in 2010, requires most derivative transactions to be centrally cleared and/or executed on an exchange, and additional capital and margin requirements are required to prescribed for most non-cleared trades. Non-financial entities that enter into certain derivatives contracts are exempted from the central clearing requirement; however, (i) all derivatives transactions must be reported to a central repository, (ii) the entity must obtain approval of derivative transactions from the appropriate committee of its board and (iii) the entity must notify the Commodity Futures Trading Commission (the CFTC) of its ability to meet its financial obligations before such exemption will be allowed. The CFTC has issued proposed regulations that set out the circumstances under which certain end users could elect to be exempt from the clearing requirements of the Dodd-Frank Act; however, we cannot predict at this time whether and to what extent any such exemption, once finalized in regulations, would be applicable to our activities. While we cannot currently predict the impact of this legislation, we will continue to monitor the potential impact of this new law as the resulting regulations emerge over the next several months and years.

ENVIRONMENTAL MATTERS

General. Our operations are subject to stringent federal, 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; and
- requiring investigatory and remedial actions to mitigate or eliminate pollution conditions caused by our operations or attributable to former operations.

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.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in compliance with existing environmental laws and regulations and 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 potentially responsible parties 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 such 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 solid wastes, including hazardous wastes, which are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended (RCRA), and comparable state statutes. RCRA regulates both hazardous wastes and nonhazardous solid wastes and 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 nonhazardous solid waste and, in some instances, hazardous wastes. While certain petroleum production wastes are excluded from 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 other 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 other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, 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, in July 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production and natural gas processing, including, among other things, a new source performance standard for volatile organic compounds that would apply to hydraulically fractured wells, compressors, pneumatic controllers, condensate and crude oil storage tanks, and natural gas processing plants. The EPA is under a court order to finalize these proposed regulations by April 3, 2012. We believe, however, that our operations will not be materially adversely affected by such existing or currently proposed requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies.

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Climate change. In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHG) present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHG from motor vehicles and also trigger construction and operating permit review for GHG emissions from certain stationary sources. In addition, EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources, including, among others, onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution activities, which may include certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

In addition, Congress has from time to time considered legislation to reduce emissions of GHG, and numerous states have taken measures to reduce emissions of GHG. The adoption of any legislation or regulations that requires reporting of GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the natural gas and NGLs we gather and process. Finally, some scientists have concluded that increasing concentrations of GHGs in the earth s atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our midstream operations.

Water Discharges. The federal Water Pollution Control Act, as amended (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. While the Clean Water Act does not require individual permits or coverage under general permits for uncontaminated discharges of storm water runoff from oil and gas facilities, some state laws may require permit coverage. 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. We believe that compliance with existing permits and foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

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 federal regulatory authority pursuant to the Safe Drinking Water Act (SDWA) over certain hydraulic fracturing activities involving the use of diesel fuel. In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. Moreover, some states, including states in which we have operations including Colorado, 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 or otherwise seek to ban fracturing activities altogether. In the event that new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of production activities, which could reduce demand for our gathering and processing services.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent standards for the treatment and disposal of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014.

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Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which are our customers, and thus reduce demand for our midstream services.

Endangered species. The Endangered Species Act, as amended (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 make a determination on listing of more than 250 species as endangered or threatened under the ESA over the next six years, through 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 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, may 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, 2011, Anadarko employed approximately 324 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 service 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 discussions by Partnership management, forward-looking statements concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including may, will, believe, expect, anticipate, estimate, continue, or other sim These statements discuss future expectations, contain projections of results of operations or financial condition or include other forward-looking information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no 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 risks and uncertainties:

our 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;

the availability of capital resources to fund acquisitions, capital expenditures and other contractual obligations, and our ability to access those resources from Anadarko or through the debt or equity capital markets;

the supply of and demand for, and the prices of, oil, natural gas, NGLs and other products or services;

the weather;

inflation;

the availability of goods and services;

general economic conditions, either internationally or nationally or in the jurisdictions in which we are doing business;

changes in environmental and safety regulations; environmental risks; regulations by the Federal Energy Regulatory Commission, (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 our sponsor, Anadarko, including changes as a result of remaining claims related to the Deepwater Horizon events for which Anadarko is not indemnified;

changes in Anadarko s capital program, strategy or desired areas of focus;

our commitments to capital projects;

the ability to utilize our revolving credit facility (RCF);

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the creditworthiness of Anadarko or our other counterparties, including financial institutions, operating partners, and other parties;

our ability to repay debt;

our ability to 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; and

other factors discussed below and elsewhere in this Item 1A and 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 our actual results to differ materially from those contained in any forward-looking statement. 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 RELATED TO 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 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, 2011, Anadarko owned or controlled 73% of our total throughput. 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. 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 system 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 general partner, any development that materially and adversely affects Anadarko s financial condition and/or its 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 and/or limit our access to borrowings on historically favorable terms.

We are substantially dependent on Anadarko as our primary customer and general partner and 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 its 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 its exploration and development activities;
- a reduction in or reallocation of Anadarko s capital budget, which could reduce the volumes available to us as a midstream operator to transport or process, limit our midstream opportunities for organic growth or limit the inventory of midstream assets we may acquire from Anadarko;
- its ability to replace reserves;
- its operations in foreign countries, which are subject to political, economic and other uncertainties;
- its drilling and operating risks, including potential environmental liabilities such as those associated with the Deepwater Horizon events, discussed below;
- transportation capacity constraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation.

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 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 our 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 we receive therein, 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, 2011, 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 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 gathering 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 gathering 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 could have a negative impact on 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 distribution of $0.44 per unit per quarter, or $1.76 per unit per year, we will require available cash of approximately $43.0 million per quarter, or $172.1 million per year, based on the number of general partner units and common units outstanding at February 1, 2012. 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;

the level of our operating and maintenance and general and administrative costs;

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, including the following, some of which are beyond our control:

- the level of capital expenditures we make;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- 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 production in our areas of operation, resulting in reduced throughput on our systems. Any such decline may cause our current or potential customers to delay drilling or shut in production, and potentially affect our vendors , suppliers and customers ability to continue operations. In addition to reducing natural gas volumes on our systems, 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 or deploy new technologies to known natural gas fields;
- the levels of domestic production and consumer demand, as affected by, among other things, concerns over inflation, geopolitical issues and the availability and cost of credit;

the availability of imported or a market for exported liquefied natural gas;

the availability of transportation systems with adequate capacity;

the volatility and uncertainty of regional pricing differentials such as in the 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.

Based on gross margin for the year ended December 31, 2011, approximately 28% of our processing services are provided under percent-of-proceeds and keep-whole arrangements under which the associated revenues and expenses are directly correlated with the prices of natural gas, condensate and NGLs. These percentages 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 fixed-price swap agreements with Anadarko expiring at various times through September 2015 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 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 the following instances:

- the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; or

- we are unable to replace the existing hedging arrangements when they expire.

If we are unable to effectively manage the commodity price risk associated with our commodity-exposed contracts, 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.

We may not be able to obtain funding or obtain funding on acceptable terms. 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 could increase if lenders and institutional investors increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity at all or on terms similar to the borrower s current debt, or reduce, or in some cases, cease 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 or cash flows.

Our significant indebtedness, and any future indebtedness, and the restrictions in our debt agreements may adversely affect our future financial and operating flexibility and our ability to service our 5.375% Senior Notes due 2021 (the Notes).

As of December 31, 2011, we had consolidated indebtedness of $669.2 million consisting of approximately $494.2 million attributable to the Notes and a $175.0 million note payable to Anadarko. In addition, as of December 31, 2011, we were able to incur an additional $800.0 million of indebtedness under our RCF. Our substantial indebtedness and the additional debt we may incur in the future for potential acquisitions or operating activities may adversely affect our liquidity and therefore our ability to make interest payments on the Notes.

Among other things, our significant indebtedness may be viewed negatively by credit rating agencies, which could result in increased costs for us to access the capital markets. Any future downgrade of the debt issued by us or our subsidiaries could significantly increase our capital costs or adversely affect our ability to raise capital in the future.

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Debt service obligations and restrictive covenants in the RCF and the indenture governing the Notes may adversely affect our ability to finance future operations, pursue acquisitions and fund other capital needs. In addition, this leverage may make our results of operations more susceptible to adverse economic or operating conditions by limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate and may place us at a competitive disadvantage as compared to our competitors that have less debt.

The Notes are our senior unsecured obligations and as a result, are effectively junior to our future secured indebtedness, to the extent of the value of the collateral securing such indebtedness, and to the indebtedness and other liabilities of our subsidiaries that do not guarantee the Notes.

The Notes are our senior unsecured obligations and will rank equally in right of payment with all of our other existing and future senior indebtedness. Although all of our wholly owned subsidiaries guarantee the Notes, in the future, under certain circumstances the guarantees may be released, and we may have subsidiaries that are not guarantors. A guarantor s guarantee will be released if, among other things, such guarantor is released from its guarantee obligations under our RCF, which would occur if, among other things, we receive investment grade ratings from two of Standard & Poor s Ratings Services, Moody s Investors Services, Inc. and Fitch Ratings Ltd. In that case, the Notes would be structurally subordinated to the claims of all creditors, including trade creditors and tort claimants, of our non-guarantor subsidiaries. In the event of the liquidation, dissolution, reorganization, bankruptcy or similar proceeding of the business of a subsidiary that is not a guarantor, creditors of that subsidiary, including trade creditors, would generally have the right to be paid in full before any distribution is made to us or the holders of the Notes.

Accordingly, there may not be sufficient funds remaining to pay amounts due on all or any of the Notes. As of December 31, 2011, our subsidiaries had no debt for borrowed money owing to any unaffiliated third parties (other than guarantees of our RCF). However, such subsidiaries are not prohibited under the indenture from incurring indebtedness in the future.

In addition, because the Notes and the guarantees of the Notes are unsecured, holders of any secured indebtedness of ours or our subsidiaries would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of the Notes. Currently, neither we nor any of our subsidiary guarantors have any secured indebtedness. Although the indenture governing the Notes places some limitations on our ability to create liens securing indebtedness, there are significant exceptions to these limitations that will allow us to secure significant amounts of indebtedness without equally and ratably securing the Notes. If we or our subsidiaries incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, our and our subsidiaries assets would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on the Notes. Consequently, any such secured indebtedness would effectively be senior to the Notes and the guarantees of the Notes, to the extent of the value of the collateral securing such secured indebtedness. In that event, you may not be able to recover all the principal or interest you are due under the Notes.

Restrictions in our Notes or RCF may limit our ability to make distributions and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in the indenture governing the Notes and 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 indenture governing the Notes and RCF contain covenants, some of which may be modified or eliminated upon our receipt of an investment grade rating, that restrict or limit our ability to do the following:

- make distributions if any default or event of default, as defined, occurs;
- make other distributions, dividends or payments on account of the purchase, redemption, retirement, acquisition, cancellation or termination of partnership interests;
- incur additional indebtedness or guarantee other indebtedness;

grant liens to secure obligations other than our obligations under our Notes or RCF or agree to restrictions on our ability to grant additional liens to secure our obligations under our Notes or RCF;

make certain loans or investments;

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- engage in transactions with affiliates;
- make any material change to the nature of our business from the midstream energy business;
- dispose of assets; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

The RCF also contains various customary covenants, customary events of default and certain financial tests as of the end of each quarter, including a maximum consolidated leverage ratio (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 (Consolidated EBITDA) 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, and a minimum consolidated interest coverage ratio (which is defined as the ratio of Consolidated EBITDA for the most recent four consecutive fiscal quarters to consolidated interest expense for such period) of 2.0 to 1.0. See Item 7 in 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.

Future levels of 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 affect any of these actions on satisfactory terms or at all.

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

Interest rates may increase in the future, whether because of inflation, increased yields on U.S. Treasury obligations or otherwise. In such cases, the interest rates on our floating rate debt, including amounts outstanding under our RCF, would increase. If interest rates rise, our future financing costs could increase accordingly. In addition, as is true with other master limited partnerships (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.

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If Anadarko were to limit divestitures 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 could result from a number of factors beyond our control, such as a change in control of Anadarko, and 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, revenues and costs, including synergies;
- an inability to successfully integrate the assets or businesses we acquire;
- 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, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

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; accordingly, 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 capital expenditures and 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, 2011, on all of our units and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $172.1 million.

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

We 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 lives of the reserves connected to our systems are less than we anticipate and we are unable to secure additional sources of natural gas, 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.

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

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

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

If natural gas and NGL prices continue to decrease, we may be required to write-down the value of our midstream properties if the estimated future cash flows from these properties fall below their net book value. Because we are an affiliate of Anadarko, the assets we acquire from it 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, 2011, we had approximately $64.1 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 lower sustained 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.

If third-party pipelines or other facilities interconnected to our gathering or transportation 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 and transportation 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 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.

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Our interstate natural gas transportation operations are subject to regulation by FERC, which could have an adverse impact on our ability to establish transportation rates that would allow us to earn a reasonable return on our investment, or even recover the full cost of operating our pipeline, thereby adversely impacting our ability to make distributions.

MIGC, our interstate natural gas transportation system, is subject to regulation by FERC under the NGA, the NGPA 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 the following:

- rates, services and terms and conditions of service;
- the types of services MIGC may offer to its customers;
- 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;
- the 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 to be not 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 a FERC-approved tariff. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing transportation service.

Should we fail to comply with any 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 under the NGA and 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.

Increased regulation of hydraulic fracturing could result in increased costs and additional 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 federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and has begun the process of drafting guidance documents related to this asserted regulatory authority.

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In addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Moreover, some states in which we operate, including Colorado, 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 or otherwise seek to ban fracturing activities altogether. In the event that new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of production activities, which could reduce demand for our gathering and processing services.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent standards for the treatment and disposal of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which are our customers, and thus reduce demand for our midstream services.

The adoption of climate change legislation or regulations restricting emission of GHGs 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.

Following its determination that emissions of CO_2, methane and other GHG present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act, including one that establishes motor vehicle GHG emission standards and another that requires Prevention of Significant Deterioration (PSD) and Title V permit reviews for the GHG emissions from stationary sources. Regulations adopted by the EPA have tailored the PSD and Title V permitting programs so that they apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. In addition, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from certain sources, including, among others, onshore and offshore oil and natural gas production and onshore oil and natural gas processing, transmission, storage, and distribution facilities, which includes certain of our operations, on an annual basis. Congress has from time to time considered legislation to reduce emissions of GHG, and numerous states have already taken legal measures to reduce emissions of GHG, 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 GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG 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 revenues, results of operations and cash available for distribution.

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Implementation of financial reform legislation and regulations 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 U.S. Congress in 2010 adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership or Anadarko, that participate in that market. This legislation, signed into law by the President on July 21, 2010, required the Commodity Futures Trading Commission (CFTC) and the SEC to promulgate implementing rules and regulations within 360 days from the date of enactment. In December, 2011, the CFTC extended temporary exemptive relief from regulations on certain provisions of the Act applicable to swaps until no later than July 16, 2012. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalent. Certain bona fide hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict whether the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our commodity price management activities, although the application of those provisions to us is uncertain at this time. 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. The legislation and any implementing 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.

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.

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas pipelines, other than MIGC, meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC policy concerning where to draw the line between activities it regulates and activities excluded from its regulation has changed. 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. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, 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.

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

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT through the PHMSA has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in high consequence areas, including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require the following of 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;

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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 DOT regulations for intrastate gathering and transmission lines. At this time, we cannot predict the ultimate cost of compliance with this regulation, 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 or 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 and regulations that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. Only recently, on January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which act, among other things, 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 and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. These safety enhancement requirements and other provisions of this act 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 financial position or results of operations.

FERC regulation of MIGC, including the outcome of certain FERC proceedings on the appropriate treatment of tax allowances included in regulated rates and the appropriate return on equity, may reduce our transportation revenues, affect our ability to include certain costs in regulated rates and increase our costs of operations, and thus adversely affect our cash available for distribution.

FERC has certain proceedings pending, which concern the appropriate allowance for income taxes that may be included in cost-based rates for FERC-regulated pipelines owned by publicly traded partnerships that do not directly pay federal income tax. FERC issued a policy statement permitting such tax allowances in 2005. FERC s policy and its initial application in a specific case were upheld on appeal by the D.C. Circuit in May of 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 is applied in practice to pipelines owned by publicly traded partnerships could impose limits on our ability to include a full income tax allowance in cost of service.

FERC issued a policy statement on April 17, 2008, regarding the composition of proxy groups for purposes of determining natural gas and oil pipeline equity returns to be included in cost-of-service based rates. In the policy statement, FERC determined that MLPs should be included in the proxy group used to determine return on equity, and made various determinations on how the FERC s DCF methodology should be applied for MLPs. 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 application of the policy statement in individual pipeline proceedings is subject to challenge in those proceedings.

The ultimate outcome of these proceedings is not certain and may result in new policies being established by FERC applicable to MLPs. Any such policy developments may adversely affect the ability of MIGC to achieve a reasonable level of return or impose limits on its ability to include a full income tax allowance in cost of service, and therefore could adversely affect our revenues and cash available for distribution.

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

Our operations are subject to stringent federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. 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 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.

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. Such expansion 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 joint venture legal entities, which affect our ability to operate and/or control these entities. In addition, 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 and White Cliffs 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 or White Cliffs 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 51% membership interest in Chipeta, we became party to Chipeta s limited liability company agreement, as amended and restated as of July 23, 2009. 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 may be 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 condition 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, earthquakes, tornadoes, floods, fires and other natural disasters and acts of terrorism or cyber-security events;
- inadvertent damage from motor vehicles or 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;

- spills or other unauthorized releases of natural gas, NGLs, other hydrocarbons or waste materials that contaminate the environment, including soils, surface water and groundwater, and otherwise adversely impact natural resources; and

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

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 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 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, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. 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 to unitholders 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 and we make sufficient expenditures 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 owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Anadarko and our general partner have conflicts of interest with, and may favor Anadarko s interests to the detriment of our unitholders.

Anadarko owns and controls our general partner and has the power to appoint all of the officers and directors of our general partner, some of whom are also officers of Anadarko. Although our general partner has a fiduciary 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, Anadarko. Conflicts of interest may arise between Anadarko 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 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 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.
- 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.
- 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 IDRs.

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.

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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.

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 our general partner s 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.

Anadarko is not limited in its ability to compete with us and is not 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.

Anadarko is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Anadarko 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 will be substantial and will reduce our cash available for distribution to our unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making distributions on our common units, we will reimburse Anadarko, which owns and controls our general partner, and its affiliates for all 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 will reduce the amount of cash otherwise available for distribution to our unitholders.

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

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

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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 fiduciary 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. Furthermore, we used substantially all of the net proceeds from our initial public offering to make a loan to Anadarko, and therefore, the net proceeds from our initial public offering were not used to grow our business.

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;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels; and

whether or not 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.

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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 fiduciary 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, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, 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. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will 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 initially remove our general partner without its consent.

The unitholders initially will be 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 23, 2012, Anadarko owns 44.5% of our outstanding common units.

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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 further 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 the unitholders. Furthermore, our partnership agreement does not restrict the ability of Anadarko to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner 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.

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

As of February 23, 2012, Anadarko holds an aggregate of 40,422,004 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 23, 2012, Anadarko owns approximately 44.5% of our outstanding common units.

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

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

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

- 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 (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 and their estimates of our financial performance;
- the public s reaction to our press releases, announcements and our 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.

TAX RISKS TO COMMON UNITHOLDERS

Our tax treatment depends on our status as a partnership for 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 additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would 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 federal income tax purposes. We have not requested, nor do we plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are 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 the unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to a material amount of entity-level taxation at the state or federal level. In addition, if we are deemed to be an investment company, as described above, we would be subject to such taxation.

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 at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to our unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

The tax treatment of publicly traded partnerships or an investment in our common units is 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 interpretation at any time. Any modification to the U.S. federal income tax laws or interpretations thereof could make it more difficult or impossible to meet the requirements for us to be treated as a partnership for U.S. federal income tax purposes, affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. Modifications to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively. We are unable to predict any particular change. Any potential change in law or interpretation thereof could negatively impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular 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 prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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If the IRS contests the federal income tax positions we take or the pricing of our related party agreements with Anadarko, 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. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. If the IRS were successful in any such challenge, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders and our general partner. Such a reallocation may require us and our unitholders to file amended tax returns. 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.

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

If a unitholder disposes of 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 decrease 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 her, if she sells such units at a price greater than her 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 items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells her units, she 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 (IRAs) and non-U.S. persons raises 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 may be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons may 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.

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We treat each purchaser of our common units as having the same tax benefits without regard to the actual common units 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 adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Our counsel is unable to opine on the validity of such filing positions. 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 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 will 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.

A unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having 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 a unitholder whose common units are loaned to a short seller to cover a short sale of common units may be considered as having disposed of the loaned common units, 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 to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, 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 to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the 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 fiscal 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 the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder s taxable income for the year of termination. Our termination currently 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 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, 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, 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 that impose a personal income tax. It is the responsibility of each unitholder to file all required U.S. federal, foreign, state and local tax returns. Our counsel has not rendered an opinion on the foreign, state or local tax consequences of an investment in our common units.

Item 1B. Unresolved Staff Comments

None

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.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

MARKET INFORMATION

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

	0000000 Fourth Quarter	0000000 Third Quarter	0000000 Second Quarter	0000000 First Quarter
2011				
High Price	**$ 41.35**	**$ 37.43**	**$ 37.48**	**$ 36.40**
Low Price	**$ 31.40**	**$ 30.75**	**$ 33.83**	**$ 29.96**
Distribution per common unit	**$ 0.440**	**$ 0.420**	**$ 0.405**	**$ 0.390**
2010				
High Price	$ 31.35	$ 27.17	$ 23.95	$ 23.50
Low Price	$ 27.12	$ 21.25	$ 19.78	$ 19.42
Distribution per common unit	$ 0.380	$ 0.370	$ 0.350	$ 0.340

As of February 23, 2012, there were approximately 21 unitholders of record of the Partnership s 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 1,852,527 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

Securities authorized for issuance under equity compensation plans. In connection with the closing of our initial public offering, our general partner adopted the Western Gas Partners, LP 2008 Long-Term Incentive Plan (LTIP), which permits the issuance of up to 2,250,000 units, of which 2,160,848 units remain available for future issuance as of December 31, 2011. Phantom unit grants have been made to each of the independent directors of our general partner and certain employees under the LTIP. 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 incentive distribution rights (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, 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.

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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	
		Limited Partner	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, that there are no arrearages on common units and 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

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, we closed our initial public offering. Concurrent with the closing of the offering, 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 closed the Powder River acquisition with Anadarko, which included (i) the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% limited liability company membership interest in Fort Union Gas Gathering, LLC (Fort Union). In July 2009, we closed on the acquisition of Chipeta Processing LLC (Chipeta) with Anadarko. We closed on 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 Pipeline, LLC (White Cliffs), which consisted of a 9.6% third-party interest, and a 0.4% interest from Anadarko. Anadarko acquired MIGC, the Powder River assets and the Granger assets in connection with its August 23, 2006, acquisition of Western and acquired the Chipeta assets and Wattenberg assets in connection with its August 10, 2006, acquisition of Kerr-McGee. Anadarko made its initial investment in White Cliffs on January 29, 2007. 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, who began construction of the Bison assets in 2009 and placed them in service in June 2010. See *Note 2. Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our acquisitions from Anadarko are considered transfers of net assets between entities under common control. Accordingly, our consolidated financial statements include (i) the combined financial results and operations of AGC and PGT from their inception through the closing date of our initial public offering and (ii) the consolidated financial results and operations of Western Gas Partners, LP and its subsidiaries from the closing date of our initial public offering thereafter, combined with (a) the financial results and operations of MIGC, the Powder River assets and Granger assets, from August 23, 2006, thereafter, (b) the financial results and operations of the Chipeta assets and Wattenberg assets, from August 10, 2006, thereafter, (c) the 0.4% interest in White Cliffs from January 29, 2007, thereafter, and (d) the financial results and operations of the Bison assets which Anadarko placed in service in 2009.

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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	0000000000 2011	0000000000 Summary Financial Information 2010	0000000000 2009	0000000000 2008	0000000000 2007
Statement of Income Data (for the year ended):					
Total revenues	**$ 664,080**	$ 505,201	$ 490,546	$ 698,768	$ 556,874
Costs and expenses	**400,139**	281,215	295,742	461,736	361,975
Depreciation, amortization and impairments	**88,454**	73,791	66,802	71,040	58,867
Total operating expenses	**488,593**	355,006	362,544	532,776	420,842
Operating income	**175,487**	150,195	128,002	165,992	136,032
Interest income (expense), net	**(14,659)**	(5,051)	6,705	11,784	(5,667)
Other income (expense), net	**(1,624)**	(2,123)	62	199	52
Income tax expense (1)	**2,161**	9,142	17,260	43,747	46,012
Net income	**157,043**	133,879	117,509	134,228	84,405
Net income (loss) attributable to noncontrolling interests	**14,103**	11,005	10,260	7,908	(92)
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249	$ 126,320	$ 84,497
Key Performance Measures (for the year ended):					
Gross margin	**$ 416,778**	$ 348,152	$ 326,474	$ 365,886	$ 303,431
Adjusted EBITDA attributable to Western Gas Partners, LP (2)	**261,366**	214,378	184,986	229,926	192,231
Distributable cash flow (2)	**221,659**	189,663	167,536	201,250	n/a
General partner interest in net income (3)	**8,599**	3,067	1,428	842	n/a
Limited partners interest in net income (3)	**131,560**	111,064	69,980	41,261	n/a
Net income per common unit (basic and diluted) (3)	**$ 1.64**	$ 1.66	$ 1.25	$ 0.78	n/a
Net income per subordinated unit (basic and diluted) (3)	**$ 1.28**	$ 1.61	$ 1.24	$ 0.77	n/a
Distributions per unit	**$ 1.6550**	$ 1.4400	$ 1.2600	$ 0.7582	n/a
Balance Sheet Data (at period end):					
Net property, plant and equipment	**$ 1,770,934**	$ 1,446,043	$ 1,389,843	$ 1,364,452	$ 1,270,309
Total assets	**2,451,620**	1,856,130	1,817,773	1,762,017	1,360,104
Total long-term liabilities	**732,820**	535,840	448,544	454,040	406,834
Total equity and partners capital	**$ 1,647,706**	$ 1,274,426	$ 1,334,052	$ 1,239,593	$ 912,504
Cash Flow Data (for the year ended):					
Net cash flows provided by (used in):					
Operating activities	**$ 270,414**	$ 226,417	$ 163,770	$ 216,795	$ 155,480
Investing activities	**(465,500)**	(877,656)	(204,550)	(578,290)	(162,250)
Financing activities	**394,571**	608,329	74,690	397,569	6,312
Capital expenditures	**$ 135,495**	$ 130,149	$ 102,717	$ 135,196	$ 154,850
Operating Data (volumes in MMcf/d):					
Gathering, treating and transportation throughput (4)	**1,265**	1,124	1,145	1,218	1,222
Processing throughput (5)	**863**	681	637	524	323
Equity investment throughput (6)	**71**	116	120	112	84

Total throughput		**2,199**		1,921		1,902		1,854		1,629
Throughput attributable to noncontrolling interests		**242**		197		180		124		
Throughput attributable to Western Gas Partners, LP		**1,957**		1,724		1,722		1,730		1,629
Gross margin per Mcf [7]	**$**	**0.52**	$	0.50	$	0.47	$	0.54	$	0.51
Gross margin per Mcf attributable to Western Gas Partners, LP [8]	**$**	**0.55**	$	0.52	$	0.49	$	0.56	$	0.51

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(1) Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, including and subsequent to our acquisition of the Partnership assets, 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. We did not utilize a Distributable cash flow measure prior to becoming a publicly traded partnership in 2008 and, as such, did not differentiate between maintenance and expansion capital expenditures prior to 2008.

(3) Net income for periods including and subsequent to 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 the Parent. All subordinated units were converted to common units on a one-for-one basis on August 15, 2011. 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 from the Chipeta assets of 24 MBbls/d, 14 MBbls/d, 11 MBbls/d and 3 MBbls/d for the years ended December 31, 2011, 2010, 2009 and 2008, respectively. The line was placed in service in 2008, therefore no volumes were excluded for 2007.

(5) Consists of 100% of Chipeta, Granger and Hilight system volumes and 50% of Newcastle system volumes for all periods presented as well as throughput beginning March 2011 attributable to the Platte Valley system.

(6) Represents our 14.81% share of Fort Union s gross volumes and excludes 4 MBbls/d and 3 MBbls/d of oil pipeline volumes for the years ended December 31, 2011 and 2010, respectively, representing our 10% share of average White Cliffs pipeline volumes. Our 10% share of White Cliffs volumes for 2009 was not material. The White Cliffs pipeline was placed in service in 2009 therefore no volumes were excluded for 2008 and 2007.

(7) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total natural gas throughput, including 100% of gross margin and volumes attributable to Chipeta and our 14.81% interest in income and volumes attributable to Fort Union.

(8) Average for period. Calculated as gross margin, excluding the noncontrolling interest owners proportionate share of revenues and cost of product, divided by total throughput attributable to Western Gas Partners, LP. Calculation includes income attributable to our investments in Fort Union and White Cliffs and volumes attributable to our investment in Fort Union.

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

EXECUTIVE SUMMARY

We are a growth-oriented master limited partnership (MLP) organized by Anadarko to own, operate, acquire and develop midstream energy assets. We currently operate in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming) and the Mid-Continent (Kansas and Oklahoma) and are engaged primarily in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, NGLs and crude oil for Anadarko and third-party producers and customers. As of December 31, 2011, our assets consist of eleven gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline, and interests in a gas gathering system and a crude oil pipeline accounted for under the equity method.

Significant financial highlights during the year ended December 31, 2011, include the following:

- We completed two acquisitions: the February acquisition of the Platte Valley gathering system and processing plant from a third party, and the July acquisition of Anadarko s Bison gas treating facility located in the Powder River Basin in northeastern Wyoming. See *Acquisitions* under Items 1 and 2 of this Form 10-K for additional information.

- Our stable operating cash flow enabled us to raise our distribution to $0.44 per unit for the fourth quarter of 2011, representing a 5% increase over the distribution for the third quarter of 2011, a 16% increase over the distribution for the fourth quarter of 2010, and our eleventh consecutive quarterly increase.

- We entered into an amended and restated $800.0 million senior unsecured revolving credit facility (the RCF) to amend and restate our $450.0 million revolving credit facility and issued $500.0 million aggregate principal amount of 5.375% Senior Notes due 2021 (the Notes). See *Liquidity and Capital Resources* within this Item 7 for additional information.

- We issued an aggregate 9,602,813 common units to the public, generating net proceeds of $335.3 million, including the general partner s proportionate capital contribution to maintain its 2.0% general partner interest. Net proceeds from the two offerings were used to repay amounts outstanding under our revolving credit facility and for general partnership purposes.

Significant operational highlights during the year ended December 31, 2011, include the following:

- Gross margin (total revenues less cost of product) attributable to Western Gas Partners, LP averaged $0.55 per Mcf for the year, representing a 6% increase compared to the year ended December 31, 2010.

- Throughput attributable to Western Gas Partners, LP totaled 1,957 MMcf/d for the year, representing a 14% increase compared to the same period in 2010.

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OUR OPERATIONS

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with our consolidated financial statements and notes to consolidated financial statements, which are included in Item 8 of this Form 10-K. Unless the context otherwise requires, references to we, us, our, the Partnership or Western Gas Partners refers to Western Gas Partners, LP and its subsidic The Partnership s general partner is Western Gas Holdings, LLC (the general partner), a wholly owned subsidiary of Anadarko Petroleum Corporation. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner.

References to the Partnership assets refer collectively to the assets owned by the Partnership as of December 31, 2011. Because of Anadarko s control of the Partnership through its ownership of our general partner, each acquisition of Partnership assets through December 31, 2011, except for those from third parties, was considered a transfer of net assets between entities under common control (see Note 2. Acquisitions in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K). As a result, after each acquisition of assets from Anadarko, we are required to revise our financial statements to include the activities of the Partnership assets as of the date of common control. As such, our historical financial statements have been recast in this Form 10-K to include the results attributable to the Bison assets as if we owned such assets for all periods presented. The consolidated financial statements for periods prior to our acquisition of the Partnership assets 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 as being our historical financial results. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union Gas Gathering, LLC (Fort Union) and White Cliffs Pipeline, LLC (White Cliffs).

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, 2011, approximately 75% of our total revenues and 73% of our throughput was 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 the gathering systems connected to the Wattenberg field and the gathering systems included in our initial assets. Specifically, 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, 2011, approximately 72% of our gross margin was attributed to fee-based contracts, under which a fixed fee is received based on the volume and 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 we retain and sell drip condensate that is recovered during the gathering of natural gas from the wellhead. Fee-based gross margin includes equity income from our interests in Fort Union and White Cliffs. Certain of our fee-based contracts contain keep-whole provisions.

For the year ended December 31, 2011, approximately 28% of our gross margin was attributed to percent-of-proceeds and keep-whole contracts, pursuant to which we have commodity price exposure, including gross margin attributable to condensate sales. We have fixed-price swap agreements with Anadarko to manage the commodity price risk inherent in substantially all of our percent-of-proceeds and keep-whole contracts. See *Note 5. Transactions with Affiliates* of the *Notes to Consolidated Financial Statements* included under Item 8 of this Form 10-K.

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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 and subsequent acquisitions from Anadarko and third parties, the results of operations, financial position and cash flows may vary significantly for 2011, 2010 and 2009 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 and (6) Distributable cash flow.

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, 2011, we added 105 receipt points to our systems with initial throughput of approximately 1.0 MMcf/d per receipt point.

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. Operation 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 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 reimbursements attributable to costs incurred on our behalf and allocations of general and administrative costs by Anadarko and the general partner to us. For these periods, Anadarko received compensation or reimbursement through a management services fee. For periods subsequent to our acquisition of the Partnership assets, Anadarko is no longer compensated for corporate services through a management services fee. Instead, we reimburse Anadarko for general and administrative expenses incurred on our behalf pursuant to the terms of our omnibus agreement with Anadarko. Amounts required to be reimbursed to Anadarko under the omnibus agreement 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;

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- 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.

In addition to the above, pursuant to the terms of the omnibus agreement with Anadarko, we are required to reimburse Anadarko for allocable general and administrative expenses. See further detail under *Items Affecting the Comparability of Our Financial Results General and administrative expenses under the omnibus agreement* below and *Note 5. Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Adjusted EBITDA. We define Adjusted EBITDA as net income (loss) attributable to Western Gas Partners, LP, plus distributions from equity investees, non-cash equity-based compensation expense, expense in excess of the omnibus cap, interest expense, income tax expense, depreciation, amortization and impairments, and other expense, less income from equity investments, interest income, income tax benefit, other income and other nonrecurring adjustments that are not settled in cash. 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.

Distributable cash flow should not be considered an alternative to net income, earnings per unit, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. Furthermore, 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 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 or net cash provided by operating activities. 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. You should not consider Adjusted EBITDA or Distributable cash flow 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.

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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.

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:

	00000000	00000000	00000000
	Year Ended December 31,		
thousands	**2011**	**2010**	**2009**
Reconciliation of Adjusted EBITDA to Net income attributable to Western Gas Partners, LP			
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 261,366**	$ 214,378	$ 184,986
Less:			
Distributions from equity investees	**10,612**	5,935	5,552
Non-cash equity-based compensation expense	**13,754**	4,787	3,580
Expenses in excess of omnibus cap		133	842
Interest expense	**31,559**	21,951	10,195
Income tax expense	**2,161**	9,142	17,260
Depreciation, amortization and impairments (1)	**85,701**	70,970	64,595
Other expense (1)	**3,683**	2,393	
Add:			
Equity income, net	**10,091**	6,640	7,330
Interest income affiliates	**16,900**	16,900	16,900
Other income (1)	**2,053**	267	57
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249
Reconciliation of Adjusted EBITDA to Net cash provided by operating activities			
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 261,366**	$ 214,378	$ 184,986
Adjusted EBITDA attributable to noncontrolling interests	**16,850**	13,823	12,462
Interest income (expense), net	**(14,659)**	(5,051)	6,705
Expenses in excess of omnibus cap		(133)	(842)
Non-cash equity-based compensation expense	**(13,754)**	(4,787)	(3,580)
Current income tax expense	**3,190**	6,076	(21,330)
Other income (expense), net	**(1,624)**	(2,123)	62
Distributions from equity investees less than (in excess of) equity income, net	**(521)**	705	1,778
Changes in operating working capital:			
Accounts receivable and natural gas imbalance receivable	**(4,114)**	339	6,087
Accounts payable, accrued liabilities and natural gas imbalance payable	**23,342**	10,785	(20,071)
Other	**338**	(7,595)	(2,487)
Net cash provided by operating activities	**$ 270,414**	$ 226,417	$ 163,770

(1) Includes our 51% share of depreciation, amortization and impairments; other expense; and other income attributable to Chipeta.

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thousands except Coverage ratio	2011	2010	2009
	00000000	00000000	00000000
	Year Ended December 31,		
Reconciliation of Distributable cash flow to Net income attributable to Western Gas Partners, LP			
Distributable cash flow	**$ 221,659**	$ 189,663	$ 167,536
Less:			
Distributions from equity investees	**10,612**	5,935	5,552
Non-cash equity-based compensation expense	**13,754**	4,787	3,580
Expenses in excess of omnibus cap		133	842
Interest expense, net (non-cash settled)	**1,214**	3,157	(239)
Income tax expense	**2,161**	9,142	17,260
Depreciation, amortization and impairments [1]	**85,701**	70,970	64,595
Other expense [1]	**3,683**	2,393	
Add:			
Equity income, net	**10,091**	6,640	7,330
Cash paid for maintenance capital expenditures [1]	**25,652**	22,314	23,916
Capitalized interest	**420**		
Cash paid for income taxes	**190**	507	
Other income [1]	**2,053**	267	57
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249
Distribution declared for the year ended December 31, 2011 [2]			
Limited partners	**143,734**		
General partner	**8,847**		
Total	**$ 152,581**		
Distribution Coverage ratio	**1.45x**		

(1) Includes our 51% share of depreciation, amortization and impairments; other expense; cash paid for maintenance capital expenditures; and other income attributable to Chipeta.

(2) Reflects distributions of $1.655 per unit declared for the year ended December 31, 2011.

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:

Affiliate contracts. Effective October 1, 2009, contracts covering substantially all of the Granger assets affiliate throughput were converted from primarily keep-whole contracts into a ten-year fee-based arrangement and, effective July 1, 2010, contracts covering all of Wattenberg s affiliate throughput were converted from primarily keep-whole contracts into a ten-year fee-based agreement. These contract changes will impact the comparability of the statements of income and cash flows. 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 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 Hilight, Hugoton, Newcastle, Granger and Wattenberg assets, with various expiration dates through September 2015.

In December 2011, we extended the commodity price swap agreements for the Hilight and Newcastle assets through December 2013. In December 2011, we also entered into price swap agreements related to the acquisition of Mountain Gas Resources, LLC, with forward-starting effective dates beginning January 1, 2012, and extending through December 31, 2016. See *Note 5. Transactions with Affiliates* and *Note 12. Subsequent Event* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Federal income taxes. Income earned by the Partnership, a non-taxable entity for U.S. federal income tax purposes, including and subsequent to our acquisition of the Partnership assets was subject only to Texas margin tax, while income earned prior to our acquisition of the Partnership assets was subject to federal and state income tax.

General and administrative expenses under the omnibus agreement. Pursuant to the omnibus agreement, Anadarko and the general partner perform centralized corporate functions for the Partnership. Prior to our ownership of the Partnership assets, our historical consolidated financial statements reflect a management services fee representing the general and administrative expenses attributable to the Partnership assets. During the years ended December 31, 2011, 2010 and 2009, Anadarko billed us $11.8 million, $9.0 million and $6.9 million, respectively, in allocated general and administrative expenses, which, prior to December 31, 2010, were subject to the cap contained in the omnibus agreement. For the year ended December 31, 2011, Anadarko, in accordance with the partnership agreement and omnibus agreement, determined, in its reasonable discretion, amounts to be allocated to us in exchange for services provided under the omnibus agreement. In addition, our general and administrative expenses for the years ended December 31, 2010 and 2009, included $0.1 million and $0.8 million, respectively, of expenses incurred by Anadarko and the general partner in excess of the cap contained in the omnibus agreement. Such expenses were recorded as capital contributions from Anadarko and did not impact the Partnership s cash flows. The amounts charged under the omnibus agreement are greater than amounts allocated to us by Anadarko for the aggregate management services fees reflected in our historical consolidated financial statements for periods prior to our ownership of the Partnership assets. We also incurred $7.7 million, $8.0 million and $7.5 million in public company expenses, excluding equity-based compensation, during the years ended December 31, 2011, 2010 and 2009, respectively.

Interest expense on intercompany balances. For periods prior to our acquisition of the Partnership assets, 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 initial public offering, the Powder River acquisition, Anadarko s initial contribution of assets of Chipeta, the Granger acquisition, Wattenberg acquisition, 0.4% interest in White Cliffs and Bison 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.

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 revolving credit facility. These assets, acquired from a third-party, have been recorded in the Partnership s 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 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.

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GENERAL TRENDS AND OUTLOOK

We expect our business to continue to be affected by the following key trends. Our expectations are based on our assumptions 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 our expectations.

Impact of natural gas prices. The relatively low natural gas price environment, which has persisted over the past three years, has led to lower levels of drilling activity 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. 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 those public funds or, in some cases, eliminated the availability of these funds to prospective issuers. If we are unable either to access the public 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 2011. Should interest rates rise, our financing costs would increase accordingly. Additionally, as with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and an associated implied distribution yield. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity, or increase the cost of issuing equity, to make acquisitions, reduce debt or for other purposes. However, we expect our cost of capital to remain competitive, as our competitors would face similar circumstances.

Acquisition opportunities. As of December 31, 2011, Anadarko s total domestic midstream asset portfolio, excluding the assets we own, consisted of nineteen gathering systems and ten processing and/or treating facilities with an aggregate throughput of approximately 2.2 Bcf/d, in addition to equity investments in two midstream projects not yet in service. A key component of our growth strategy is to acquire midstream assets from Anadarko and third parties over time.

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As of December 31, 2011, Anadarko owns a 2.0% general partner interest in us, all of our IDRs and a 43.3% limited partner interest in us. Given Anadarko s significant interests in us, we believe Anadarko will benefit from selling 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 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.

RESULTS OF OPERATIONS

OPERATING RESULTS

The following tables and discussion present a summary of our results of operations for the years ended December 31, 2011, 2010 and 2009:

	0000000000	0000000000	0000000000
	Year Ended December 31,		
thousands	**2011**	**2010**	**2009**
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 286,969**	$ 233,708	$ 226,399
Natural gas, natural gas liquids and condensate sales	**361,582**	258,820	253,618
Equity income and other, net	**15,529**	12,673	10,529
Total revenues [(1)]	**664,080**	505,201	490,546
Total operating expenses [(1)]	**488,593**	355,006	362,544
Operating income	**175,487**	150,195	128,002
Interest income affiliates	**16,900**	16,900	16,900
Interest expense	**(31,559)**	(21,951)	(10,195)
Other income (expense), net	**(1,624)**	(2,123)	62
Income before income taxes	**159,204**	143,021	134,769
Income tax expense	**2,161**	9,142	17,260
Net income	**157,043**	133,879	117,509
Net income attributable to noncontrolling interests	**14,103**	11,005	10,260
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249
Key Performance Metrics [(2)]			
Gross margin	**$ 416,778**	$ 348,152	$ 326,474
Adjusted EBITDA attributable to Western Gas Partners, LP	**$ 261,366**	$ 214,378	$ 184,986
Distributable cash flow	**$ 221,659**	$ 189,663	$ 167,536

(1) Revenues include affiliate amounts earned by the Partnership from services provided to our affiliates, as well as from the sale of residue gas, 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 attributable to Western Gas Partners, LP (Adjusted EBITDA) and Distributable cash flow are defined under the caption *How We Evaluate Our Operations* within this Item 7. Such caption also includes reconciliations of Adjusted EBITDA and Distributable cash flow to their most directly comparable measures calculated and presented in accordance with GAAP.

For purposes of the following discussion, any increases or decreases for the year ended December 31, 2011 refer to the comparison of the year ended December 31, 2011 to the year ended December 31, 2010, any increases or decreases for the year ended December 31, 2010 refer to the comparison of the year ended December 31, 2010 to the year ended December 31, 2009.

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Operating Statistics

	00000	00000	00000	00000	00000
		Year Ended December 31,			
throughput in MMcf/d	**2011**	**2010**	D	**2009**	D
Gathering, treating and transportation [(1)]	**1,265**	1,124	13%	1,145	(2)%
Processing [(2)]	**863**	681	27%	637	7%
Equity investment [(3)]	**71**	116	(39)%	120	(3)%
Total throughput [(4)]	**2,199**	1,921	14%	1,902	1%
Throughput attributable to noncontrolling interests	**242**	197	23%	180	9%
Total throughput attributable to Western Gas Partners, LP	**1,957**	1,724	14%	1,722	

(1) Excludes average NGL pipeline volumes from the Chipeta assets of 24 MBbls/d, 14 MBbls/d, and 11 MBbls/d for the years ended December 31, 2011, 2010, and 2009, respectively.

(2) Consists of 100% of Chipeta, Granger and Hilight system volumes and 50% of Newcastle system volumes for all periods presented as well as throughput beginning March 2011 attributable to the Platte Valley system.

(3) Represents our 14.81% share of Fort Union s gross volumes and excludes 4 MBbls/d and 3 MBbls/d of oil pipeline volumes for the years ended December 31, 2011 and 2010, respectively, representing our 10% share of average White Cliffs pipeline volumes. Our 10% share of White Cliffs volumes for 2009 was not material.

(4) Includes affiliate, third-party and equity-investment volumes.

Gathering, treating and transportation throughput increased by 141 MMcf/d for the year ended December 31, 2011, primarily due to the startup of the Bison assets in June 2010 and throughput increases at the Wattenberg system due to increased drilling activity in the area. These increases were partially offset by lower throughput at the MIGC system resulting from the January 2011 expiration of certain contracts that were not renewed due to the startup of the third-party owned Bison pipeline, and throughput decreases at the Haley, Pinnacle, Dew and Hugoton systems resulting from natural production declines and reduced drilling activity in those areas. Gathering, treating and transportation throughput decreased by 21 MMcf/d for the year ended December 31, 2010, primarily due to throughput decreases at the Pinnacle, Haley, Dew and Hugoton systems resulting from natural production declines and reduced drilling activity in those areas as a result of low natural gas prices. These declines were partially offset by throughput increases at the Wattenberg system due to increased drilling activity and recompletions driven by favorable producer economics in the area and the startup of the Bison assets in June 2010.

Processing throughput increased by 182 MMcf/d for the year ended December 31, 2011, primarily due to the additional throughput from the Platte Valley system acquired in February 2011, as well as throughput increases at the Chipeta and Hilight systems, resulting from drilling activity in these areas driven by the relatively high liquid content of the gas volumes produced. Processing throughput increased by 44 MMcf/d for the year ended December 31, 2010, primarily due to increased throughput at the Chipeta system due to increased drilling activities in the Natural Buttes areas and at the Granger system resulting from the temporary redirection of volumes from competing systems during the last half of 2010.

Equity investment volumes decreased by 45 MMcf/d for the year ended December 31, 2011, due to lower throughput at the Fort Union system following the startup of the Bison pipeline. Equity investment volumes decreased slightly by 4 MMcf/d for the year ended December 31, 2010, due to reduced drilling activity around the Fort Union system and natural production declines.

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Natural Gas Gathering, Processing and Transportation Revenues

	0000000	0000000	0000000	0000000	0000000
	Year Ended December 31,				
thousands except percentages	**2011**	**2010**	D	**2009**	D
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 286,969**	$ 233,708	23%	$ 226,399	3%

Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $53.3 million for the year ended December 31, 2011, due to the acquisition of the Platte Valley system in February 2011, the June 2010 startup of the Bison assets, and increased fee revenue at the Wattenberg system as a result of changes in affiliate contract terms (from primarily keep-whole and percentage-of-proceeds arrangements to fee-based arrangements), effective July 2010. These increases were partially offset by decreased fee revenue at MIGC due to the January 2011 expiration of certain contracts, along with decreased volume due to natural declines at the Haley, Hugoton and Dew systems. Gathering, processing and transportation of natural gas and natural gas liquids revenues increased by $7.3 million for the year ended December 31, 2010, due to the June 2010 startup of Bison and increased fee revenue at the Wattenberg and Granger systems. This increase resulted from changes in affiliate contract terms effective in July 2010 at Wattenberg and in October 2009 at Granger, from primarily keep-whole and percentage-of-proceeds agreements to fee-based agreements. In addition, revenues increased due to higher rates at the Pinnacle, Hugoton and Wattenberg systems. These increases were partially offset by decreased throughput at the Pinnacle, Haley, Dew and Hugoton systems.

Natural Gas, Natural Gas Liquids and Condensate Sales

	000000	000000	000000	000000	000000
thousands except percentages and	**Year Ended December 31,**				
per-unit amounts	**2011**	**2010**	D	**2009**	D
Natural gas sales	**$ 106,802**	$ 65,688	63%	$ 71,056	(8)%
Natural gas liquids sales	**227,982**	168,462	35%	164,581	2%
Drip condensate sales	**26,798**	24,670	9%	17,981	37%
Total	**$ 361,582**	$ 258,820	40%	$ 253,618	2%
Average price per unit:					
Natural gas (per Mcf)	**$ 5.77**	$ 5.83	(1)%	$ 4.11	42%
Natural gas liquids (per Bbl)	**$ 48.06**	$ 41.68	15%	$ 31.00	34%
Drip condensate (per Bbl)	**$ 72.86**	$ 70.50	3%	$ 47.87	47%

Including the effects of commodity price swap agreements, total natural gas, natural gas liquids and condensate sales increased by $102.8 million for the year ended December 31, 2011, which consisted of a $59.6 million increase in NGLs sales, a $41.1 million increase in natural gas sales and a $2.0 million increase in drip condensate sales.

The increase in NGLs sales was primarily due to a 10% increase in volumes sold resulting from the acquisition of the Platte Valley system in February 2011 and higher throughput at the Chipeta and Hilight systems, partially offset by changes in affiliate contract terms at the Wattenberg system allowing the producer to take its product in kind.

The increase in natural gas sales was due to a 64% increase in volumes sold, resulting from the acquisition of the Platte Valley system in February 2011 and higher throughput at the Hilight system due to increased third-party drilling in the area. The increase in drip condensate sales for the year ended December 31, 2011, was primarily due to a higher average sales price at the Wattenberg and Hugoton systems and Platte Valley sales.

Total natural gas, natural gas liquids and condensate sales increased by $5.2 million for the year ended December 31, 2010, consisting of a $3.8 million and $6.8 million increase in NGLs sales and drip condensate sales, respectively, partially offset by a $5.4 million decrease in natural gas sales. The increase in NGLs sales is primarily attributable to a 34% increase in the average price of NGLs for 2010. This increase was partially offset by a 24% decrease in the volume of NGLs sold primarily due to the changes in affiliate contract terms at the Granger and Wattenberg systems effective in October 2009 and July 2010, respectively, allowing the producer to take its liquids and gas in-kind.

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The decrease in natural gas sales was due to a 35% decrease in the volume of natural gas sold primarily due to the changes in affiliate contract terms at the Granger and Wattenberg systems. The decrease was partially offset by a 42% increase in the average natural gas sales price. Natural gas and NGL prices pursuant to the commodity price swap agreements for the Granger system in 2010 were higher than 2009 market prices, and natural gas and NGL prices pursuant to the 2010 commodity price swap agreements for the Hilight and Newcastle systems were higher than 2009 commodity swap prices. The increase in drip condensate sales for the year ended December 31, 2010, was primarily due to a $22.63 per Bbl, or 47%, increase in the average price of condensate at the Hugoton and Wattenberg systems.

The average natural gas and NGLs prices for the year ended December 31, 2011 and 2010, include the effects of commodity price swap agreements attributable to sales for the Granger, Wattenberg, Hilight, Newcastle and Hugoton systems. See *Note 5. Transactions with Affiliates* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Cost of Product and Operation and Maintenance Expenses

	000000	000000	000000	000000	000000
	Year Ended December 31,				
thousands except percentages	**2011**	**2010**	D	**2009**	D
Cost of product	**$ 247,302**	$ 157,049	57%	$ 164,072	(4)%
Operation and maintenance	**101,754**	85,407	19%	89,535	(5)%
Total cost of product and operation and maintenance expenses	**$ 349,056**	$ 242,456	44%	$ 253,607	(4)%

Including the effects of commodity price swap agreements on purchases, cost of product expense increased by $90.3 million for the year ended December 31, 2011, primarily consisting of a $51.5 million increase due to increased throughput at the Hilight and Chipeta systems, and a $44.4 million increase due to the acquisition of the Platte Valley system, partially offset by a $6.2 million decrease due to changes in gas imbalance positions.

Including the effects of commodity price swap agreements on purchases, cost of product expense decreased by $7.0 million for the year ended December 31, 2010, primarily consisting of a $9.0 million decrease in gathering fees paid by the Granger system for volumes gathered at adjacent gathering systems owned by Anadarko and a third party, then processed at Granger. Effective in October 2009, fees previously paid by Granger are now paid directly by the producer to the other gathering system owners. Cost of product expense also decreased $5.0 million due to a decrease in natural gas purchases, primarily due to lower volumes from the changes in affiliate contract terms at the Granger and Wattenberg systems effective in October 2009 and July 2010, respectively, and lower gas prices. In addition, cost of product expense decreased $1.1 million due to a decrease in the actual cost of fuel compared to the contractual cost of fuel, and decreased $0.6 million due to changes in gas imbalance positions. These decreases were offset by an $8.8 million increase in NGL purchases, primarily due to higher prices, offset by lower volumes from the changes in affiliate contract terms at the Granger and Wattenberg systems.

Cost of product expense for the year ended December 31, 2011 and 2010, include the effects of commodity price swap agreements attributable to purchases for the Granger, Wattenberg, Hilight, Newcastle and Hugoton systems. 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 $16.3 million for the year ended December 31, 2011, primarily due to the acquisition of the Platte Valley system and the June 2010 startup of the Bison assets, partially offset by lower compressor lease expenses resulting from the purchase of compressors used at the Wattenberg system leased during 2010.

Operation and maintenance expense decreased by $4.1 million for the year ended December 31, 2010, primarily due to lower compressor lease expenses resulting from the purchase of previously leased compressors used at the Granger and Wattenberg systems during 2010, lower electricity expense at the Chipeta system, lower chemical expenses and lower contract labor. The decrease in compressor lease expense for the year ended December 31, 2010, was offset by an increase in depreciation expense discussed below under General and Administrative, Depreciation and Other Expenses. In addition, the decrease in operating expense was partially offset by higher field personnel expenses, primarily attributable to merit increases, and a $2.0 million increase due to the startup of the Bison assets in June 2010.

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General and Administrative, Depreciation and Other Expenses

	000000	000000	000000	000000	000000
		Year Ended December 31,			
thousands except percentages	**2011**	**2010**	D	**2009**	D
General and administrative	**$ 35,388**	$ 25,305	40%	$ 28,569	(11)%
Property and other taxes	**15,695**	13,454	17%	13,566	(1)%
Depreciation, amortization and impairments	**88,454**	73,791	20%	66,802	10%
Total general and administrative, depreciation and other expenses	**$ 139,537**	$ 112,550	24%	$ 108,937	3%

General and administrative expenses increased by $10.1 million for year ended December 31, 2011, due to an increase of $7.2 million in noncash payroll expenses primarily due to an increase in the collective value of awards under the Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated, from $215.00 per unit to $634.00 per unit and an increase of $2.7 million in corporate and management personnel costs allocated to us pursuant to the omnibus agreement. Property and other taxes increased by $2.2 million for the year ended December 31, 2011, primarily due to the ad valorem tax for the Platte Valley, Bison and Wattenberg assets. Depreciation, amortization and impairments increased by $14.7 million for the year ended December 31, 2011, primarily attributable to the addition of the Platte Valley and Bison assets, and depreciation associated with capital projects completed and capitalized at the Wattenberg, Hugoton and Hilight systems.

General and administrative expenses decreased by $3.3 million for the year ended December 31, 2010, due to the management fee allocated to the Granger assets and Wattenberg assets during the year ended December 31, 2009, then discontinued effective January 2010 and July 2010, respectively, upon contribution of the assets to us. This decrease was partially offset by an increase in corporate and management personnel costs allocated to us pursuant to the omnibus agreement. Depreciation, amortization and impairments increased by approximately $7.0 million for the year ended December 31, 2010, primarily attributable to capital projects completed at the Chipeta, Hilight and Hugoton systems, the addition of the Bison assets, as well as previously leased compressors used at the Granger and Wattenberg systems purchased and contributed to the Partnership during 2010.

Interest Income and Interest Expense

	000000	000000	000000	000000	000000
		Year Ended December 31,			
thousands except percentages	**2011**	**2010**	D	**2009**	D
Interest income affiliates	**$ 16,900**	$ 16,900	%	$ 16,900	%
Third Parties					
Interest expense on long-term debt	**(20,533)**	(8,530)	141%	(304)	nm [(1)]
Amortization of debt issuance costs and commitment fees [(2)]	**(5,297)**	(3,340)	59%	(555)	nm
Capitalized interest	**420**		nm		nm
Affiliates					
Interest expense on notes payable to Anadarko	**(4,935)**	(6,828)	(28)%	(8,953)	(24)%
Interest expense, net on affiliate balances [(3)]	**(1,214)**	(3,157)	(62)%	(240)	nm
Credit facility commitment fees		(96)	(100)%	(143)	(33)%
Interest expense	**$ (31,559)**	$ (21,951)	44%	$ (10,195)	115%

(1) Percent change is not meaningful (nm).

(2) For the year ended December 31, 2011, includes $0.5 million of amortization of the original issue discount and underwriters fees related to the Notes.

(3) Incurred on intercompany borrowings associated with the Bison assets in 2011, and associated with the White Cliffs investment, Bison assets and Wattenberg assets in 2010 and 2009, prior to such assets being acquired by the Partnership.

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Interest expense increased by $9.6 million for the year ended December 31, 2011, due to interest expense incurred on the Notes issued in May 2011 as well as $1.3 million of accelerated amortization expense related to the early repayment of the Wattenberg term loan in March 2011 (described in *Liquidity and Capital Resources*). The increase was partially offset by lower interest expense on amounts outstanding on our RCF during 2011, a decrease in interest expense on the Note Payable to Anadarko which was amended in December 2010 reducing the interest rate from 4.00% to 2.82% for the remainder of the term, and the repayment of the Wattenberg term loan.

Interest expense increased by $11.7 million for the year ended December 31, 2010, primarily due to interest expense incurred on the amounts outstanding during 2010 under the Wattenberg term loan, our RCF and related commitment fees, and expense incurred on intercompany borrowings associated with assets we acquired.

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

	00000000	**00000000**	**00000000**	**00000000**	**00000000**
			Year Ended December 31,		
thousands except percentages	**2011**	**2010**	D	**2009**	D
Other income (expense), net	**$ (1,624)**	$ (2,123)	(24)%	$ 62	nm

Other income (expense), net for the year ended December 31, 2011, primarily consists of the $1.9 million loss realized on an interest-rate swap agreement entered into in March 2011 and terminated in May 2011 in connection with the offering of the Notes. Other income (expense), net for the year ended December 31, 2010, primarily relates to financial agreements entered into in April 2010 to fix the underlying ten-year Treasury rates with respect to a potential note issuance that was under consideration at that time. Upon reaching our decision not to issue the notes in May 2010, we terminated the agreements at a cost of $2.4 million.

Income Tax Expense

	00000000	**00000000**	**00000000**	**00000000**	**00000000**
			Year Ended December 31,		
thousands except percentages	**2011**	**2010**	D	**2009**	D
Income before income taxes	**$ 159,204**	$ 143,021	11%	$ 134,769	6%
Income tax expense	**2,161**	9,142	(76)%	17,260	(47)%
Effective tax rate	**1%**	6%		13%	

We are not a taxable entity for U.S. federal income tax purposes, although the portion of our income apportionable to Texas is subject to Texas margin tax. Income attributable to (a) the Bison assets prior to and including June 2011, (b) the Wattenberg assets prior to and including July 2010 and (c) the Granger assets prior to and including January 2010 were subject to federal and state income tax, resulting in the lower income tax expense for the year ended December 31, 2011. Income earned by the Granger, Wattenberg and Bison assets for periods subsequent to January 2010, July 2010 and June 2011, respectively, was subject only to Texas margin tax on the portion of their incomes apportionable to Texas.

For 2011, 2010, and 2009, our variance from the federal statutory rate, which is zero percent as a non-taxable entity, is primarily attributable to federal and state taxes on income attributable to Partnership assets pre-acquisition and our share of Texas margin tax.

Noncontrolling Interests

		Year Ended December 31,			
thousands except percentages	**2011**	**2010**	D	**2009**	D
Net income attributable to noncontrolling interests	**$ 14,103**	$ 11,005	28%	$ 10,260	7%

For the year ended December 31, 2011, and 2010, net income attributable to noncontrolling interests increased by $3.1 million and $0.7 million, respectively, primarily due to the higher volumes at the Chipeta system.

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Key Performance Metrics

	00000000	00000000	00000000	00000000	00000000
	Year Ended December 31,				
thousands except percentages and gross margin per Mcf	**2011**	**2010**	D	**2009**	D
Gross margin	**$ 416,778**	$ 348,152	20%	$ 326,474	7%
Gross margin per Mcf [(1)]	**0.52**	0.50	4%	0.47	6%
Gross margin per Mcf attributable to Western Gas Partners, LP [(2)]	**0.55**	0.52	6%	0.49	6%
Adjusted EBITDA attributable to Western Gas Partners, LP [(3)]	**261,366**	214,378	22%	184,986	16%
Distributable cash flow [(3)]	**$ 221,659**	$ 189,663	17%	$ 167,536	13%

(1) Average for period. Calculated as gross margin (total revenues less cost of product) divided by total natural gas throughput, including 100% of gross margin and volumes attributable to Chipeta and our 14.81% interest in income and volumes attributable to Fort Union.

(2) Average for period. Calculated as gross margin, excluding the noncontrolling interest owners proportionate share of revenues and cost of product, divided by total throughput attributable to Western Gas Partners, LP. Calculation includes income attributable to our investments in Fort Union and White Cliffs and volumes attributable to our investment in Fort Union.

(3) For a reconciliation of Adjusted EBITDA and Distributable cash flow to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read the descriptions above under the captions *How We Evaluate Our Operations* within this Item 7.

Gross margin and Gross margin per Mcf. Gross margin increased by $68.6 million for the year ended December 31, 2011, primarily due to the acquisition of the Platte Valley system; the startup of the Bison assets in June 2010; higher margins at the Wattenberg and Chipeta systems, due to an increase in volumes (including the impact of commodity price swap agreements at the Wattenberg system); and the increase in our interest in White Cliffs from 0.4% to 10% in September 2010. These increases were partially offset by lower gross margin at the MIGC system due to the expiration of certain firm transportation contracts in January 2011 and lower gross margins at the Haley and Hugoton systems due to naturally declining production volumes. For the year ended December 31, 2011, gross margin per Mcf increased by 4% and gross margin per Mcf attributable to Western Gas Partners, LP increased by 6%, primarily due to the acquisition of the Platte Valley system in 2011 and changes in the throughput mix of the portfolio.

Gross margin increased by $21.7 million for the year ended December 31, 2010, primarily due to higher fee revenue at the Granger and Wattenberg systems resulting from the change in affiliate contract terms as well as higher throughput volumes at those systems, as well as the startup of Bison in June 2010. This increase is offset by lower throughput at the Pinnacle, Haley, Dew and Hugoton systems. Gross margin per Mcf and gross margin per Mcf attributable to Western Gas Partners, LP both increased by 6% for the year ended December 31, 2010, primarily due to the changes in contract terms mentioned above and changes in the throughput mix within our portfolio.

Adjusted EBITDA. Adjusted EBITDA increased by $47.0 million for the year ended December 31, 2011, primarily due to a $155.4 million increase in total revenues excluding equity income, partially offset by a $90.3 million increase in cost of product, a $16.3 million increase in operation and maintenance expenses and a $1.2 million increase in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the 2010 omnibus cap. Adjusted EBITDA increased by $29.4 million for the year ended December 31, 2010, primarily due to a $15.3 million increase in total revenues, excluding equity income; a $7.0 million decrease in cost of product; a $4.1 million decrease in operation and maintenance expenses; and a $3.8 million decrease in general and administrative expenses, excluding non-cash equity-based compensation and expenses in excess of the omnibus cap.

Distributable cash flow. Distributable cash flow increased by $32.0 million for the year ended December 31, 2011, primarily due to the $47.0 million increase in Adjusted EBITDA, partially offset by a $12.0 million increase in net cash paid for interest expense, a $3.3 million decrease in cash paid for maintenance capital expenditures and a $0.3 million decrease in cash paid for income taxes.

Distributable cash flow increased by $22.1 million for the year ended December 31, 2010, primarily due to the $29.4 million increase in Adjusted EBITDA and a $1.6 million increase in cash paid for maintenance capital expenditures, partially offset by an $8.4 million increase in net cash paid for interest expense and a $0.5 million decrease in cash paid for income taxes.

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Reconciliation to GAAP measures. Adjusted EBITDA and Distributable cash flow are not defined in 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, while 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 or net cash provided by operating activities. Adjusted EBITDA has important limitations as an analytical tool because it excludes some, but not all, items that affect net income and net cash provided by operating activities. You should not consider Adjusted EBITDA or Distributable cash flow 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. Furthermore, while Distributable cash flow is a measure we use to assess our performance and 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.

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.

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 owners. Our sources of liquidity as of December 31, 2011, include cash flows generated from operations, including interest income on our $260.0 million note receivable from Anadarko, available borrowing capacity under our RCF, and issuances of additional common and general partner units or debt securities. We believe that cash flows generated from the sources above will be sufficient to satisfy our short-term working capital requirements and long-term maintenance capital expenditure requirements. The amount of future distributions to unitholders will depend on results of operations, financial conditions, 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 debt and common unit 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 and have increased our quarterly distribution each quarter since the second quarter of 2009. On January 18, 2012, the board of directors of our general partner declared a cash distribution to our unitholders of $0.44 per unit, or $43.0 million in aggregate, including incentive distributions. The cash distribution is payable on February 13, 2012, to unitholders of record at the close of business on February 1, 2012.

Management continuously monitors our leverage position and coordinates its capital expenditure program, quarterly distributions and acquisition strategy with its 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 statement. Our ability to generate cash flows is subject to a number of factors, some of which are beyond our control. Please read Item 1A Risk Factors of this Form 10-K.

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Working capital. As of December 31, 2011, we had $184.5 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.

Capital expenditures. Our business is capital intensive, requiring significant investment to maintain and improve existing facilities. 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 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:

	00000000	00000000	00000000
	Year Ended December 31,		
thousands	**2011**	**2010**	**2009**
Acquisitions	**$ 330,794**	$ 752,827	$ 101,451
Expansion capital expenditures	**$ 109,748**	$ 107,790	$ 78,608
Maintenance capital expenditures	**25,747**	22,359	24,109
Total capital expenditures (1)	**$ 135,495**	$ 130,149	$ 102,717
Capital incurred (2)	**$ 141,002**	$ 136,600	$ 90,846

(1) Capital expenditures for the years ended December 31, 2011, 2010 and 2009, includes $6.0 million, $93.9 million and $64.5 million, respectively, of pre-acquisition capital expenditures for the Bison, Wattenberg and Granger assets and includes the noncontrolling interest owners share of Chipeta s capital expenditures, funded by contributions from the noncontrolling interest owners.

(2) Capital incurred for the years ended December 31, 2011, 2010 and 2009, includes $4.4 million, $98.5 million and $58.0 million, respectively, of pre-acquisition capital incurred for the Bison, Wattenberg and Granger assets and includes the noncontrolling interest owners share of Chipeta s capital incurred, funded by contributions from the noncontrolling interest owners.

Acquisitions include the Bison, Platte Valley, White Cliffs, Wattenberg, Granger and Chipeta acquisitions as outlined in *Note 2. Acquisitions* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. On December 15, 2011, we entered into a contribution agreement (the MGR Contribution Agreement) with Anadarko for the acquisition of a 100% interest in Mountain Gas Resources, LLC, which owns certain midstream assets located in southwestern Wyoming. Consideration required for the acquisition was $458.6 million in cash, 632,783 common units of the Partnership and 12,914 general partner units to be issued to the general partner. On January 13, 2012, we closed the transaction contemplated by the MGR Contribution Agreement and funded the cash consideration through (i) $299.0 million in borrowings under our RCF and (ii) the use of $159.6 million of cash on hand. See *Note 12. Subsequent Event* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

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Capital expenditures, excluding acquisitions, increased by $5.3 million for the year ended December 31, 2011. Expansion capital expenditures increased by $2.0 million for the year ended December 31, 2011, primarily due to an increase of $39.5 million in expenditures primarily at our Chipeta, Bison, Highlight and Wattenberg systems, partially offset by the purchase of previously leased compressors at the Wattenberg system during the year ended December 31, 2010, for $37.5 million. Maintenance capital expenditures increased by $3.4 million, primarily as a result of maintenance projects at the Wattenberg system and higher well connects at the Hilight system, partially offset by fewer well connections at the Haley and Hugoton systems in 2011 and improvements at the Granger system completed during 2010.

Capital expenditures increased by $27.4 million for the year ended December 31, 2010. Excluding cash paid for acquisitions, expansion capital expenditures for the year ended December 31, 2010, increased by $29.2 million, primarily due to Anadarko commencing the construction of the Bison assets in 2009 and placing them in service in June 2010, in addition to the purchase of previously leased compressors at the Granger and Wattenberg systems during 2010 prior to the Granger and Wattenberg acquisitions, offset by the completion of the cryogenic unit at the Chipeta plant and a compressor overhaul at the Hugoton system during 2009. In addition, maintenance capital expenditures decreased by $1.8 million, primarily as a result of fewer well connections.

We estimate our total capital expenditures for the year ending December 31, 2012, including our 51% share of Chipeta s capital expenditures and excluding acquisitions, to be $410 million to $460 million and our maintenance capital expenditures to be approximately 6% to 10% of total capital expenditures. Expected 2012 capital projects include our 51% share of the costs associated with the completion of a second cryogenic train at the Chipeta plant and the construction of new cryogenic processing plants in Colorado and Texas. 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 presents a summary of our net cash flows from operating activities, investing activities and financing activities.

	00000000	**00000000**	**00000000**
	Year Ended December 31,		
thousands	**2011**	**2010**	**2009**
Net cash provided by (used in):			
Operating activities	**$ 270,414**	$ 226,417	$ 163,770
Investing activities	**(465,500)**	(877,656)	(204,550)
Financing activities	**394,571**	608,329	74,690
Net increase (decrease) in cash and cash equivalents	**$ 199,485**	$ (42,910)	$ 33,910

Operating Activities. Net cash provided by operating activities increased by $44.0 million for the year ended December 31, 2011, primarily due to the following items:

- a $155.4 million increase in revenues, excluding equity income; and

- a $16.9 million increase due to changes in accounts payable balances and other items.

The impact of the above items was offset by the following:

- a $90.3 million increase in cost of product expense;

a $16.3 million increase in operation and maintenance expenses;

a $9.6 million increase in interest expense;

a $12.3 million decrease due to changes in accounts receivable balances, inclusive of $11.5 million of Contributions from Parent;

a $2.9 million increase in current income tax expense; and

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a $2.2 million increase in property and other taxes expense.

Net cash provided by operating activities increased by $62.6 million for the year ended December 31, 2010, primarily due to the following items:

a $27.4 million decrease in current income tax expense;

a $22.1 million increase due to changes in accounts payable balances and other items;

a $15.3 million increase in revenues, excluding equity income;

a $7.0 million decrease in cost of product expense; and

a $4.1 million decrease in operation and maintenance expenses.

The impact of the above items was offset by the following:

an $11.8 million increase in interest expense; and

a $2.1 million decrease due to changes in accounts receivable balances.

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

$302.0 million of cash paid for the Platte Valley acquisition;

$135.5 million of capital expenditures;

$25.0 million of cash paid for the Bison acquisition; and

$3.8 million for equipment purchases from Anadarko.

Net cash used in investing activities for the year ended December 31, 2010, included the following:

$473.1 million paid for the Wattenberg acquisition;

$241.7 million of cash paid for the Granger acquisition;

- $130.1 million of capital expenditures; and
- $38.0 million paid for the White Cliffs acquisition.

Offsetting these amounts were $5.6 million of proceeds from the sale of idle compressors to Anadarko and the sale of an idle refrigeration unit at the Granger system to a third party.

Net cash used in investing activities for the year ended December 31, 2009, included the following:

- $102.7 million of capital expenditures; and
- $101.5 million paid for the Chipeta acquisition in July 2009.

See the sub-caption Capital expenditures above within this Liquidity and Capital Resources discussion.

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

- $493.9 million of net proceeds from our Notes offering in May 2011;
- $303.0 million of borrowings to fund the Platte Valley acquisition;
- $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 both our March 2011 equity offering and Notes offering in May 2011 were used in the $619.0 million repayment of amounts outstanding under our RCF.

Net distributions to Parent attributable to pre-acquisition intercompany balances were $3.7 million during 2011, representing the net non-cash settlement of intercompany transactions attributable to the Bison assets.

Net cash provided by financing activities for the year ended December 31, 2010, included the following:

- $450.0 million of borrowings to partially fund the Wattenberg acquisition;
- $210.0 million to partially fund the Granger acquisition;
- $246.7 million of net proceeds from the November 2010 equity offering; and
- $99.1 million of net proceeds from the May 2010 equity offering.

Proceeds from both our May 2010 and November 2010 equity offerings were used in the $361.0 million repayment of amounts outstanding under our RCF.

Net contributions from Parent attributable to pre-acquisition intercompany balances were $68.9 million during 2010, representing the net non-cash settlement of intercompany transactions attributable to the Granger, Wattenberg and Bison assets.

Net cash provided by financing activities for the year ended December 31, 2009, included the following:

- $122.5 million of proceeds from the December 2009 equity offering;

$101.5 million issuance of the three-year term loan to Anadarko in connection with the Chipeta acquisition, partially offset by its repayment in October 2009; and

$4.3 million of costs paid in connection with the RCF we entered into in October 2009.

Proceeds from our December 2009 equity offering were used in the $101.5 million repayment of amounts outstanding under our RCF.

Net distributions to Parent attributable to pre-acquisition intercompany balances were $5.8 million during 2009, representing the net non-cash settlement of intercompany transactions attributable to the Chipeta, Granger, Wattenberg and Bison assets.

For the year ended December 31, 2011, 2010 and 2009 we paid $140.1 million, $94.2 million and $70.1 million, respectively, of cash distributions to our unitholders. Contributions from noncontrolling interest owners to Chipeta totaled $33.6 million, $2.1 million and $40.3 million during the year ended December 31, 2011, 2010 and 2009, respectively, primarily for expansion of the cryogenic units and plant construction. Distributions from Chipeta to noncontrolling interest owners totaled $17.5 million, $13.2 million and $8.0 million, for the year ended December 31, 2011, 2010 and 2009, respectively, representing the distributions for the four preceding quarterly periods ended September 30th of the respective year.

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Debt and credit facilities. As of December 31, 2011, our outstanding debt consisted of $494.2 million of the Notes and the $175.0 million 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.

5.375% Senior Notes due 2021. In May 2011, we completed the offering of $500.0 million aggregate principal amount of the Notes at a price to the public of 98.778% of the face amount of the Notes. Including the effects of the issuance and underwriting discounts, the effective interest rate is 5.648%. Interest on the Notes is paid semi-annually on June 1 and December 1 of each year, with payments commencing on December 1, 2011. Proceeds from the offering of the Notes (net of the underwriting discount of $3.3 million and debt issuance costs) were used to repay the then-outstanding balance on the RCF, with the remainder used for general partnership purposes.

The Notes mature on June 1, 2021, unless redeemed at a redemption price that includes a make-whole premium. We may redeem the 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 Notes to be redeemed or (ii) the sum of the present values of the remaining scheduled payments of principal and interest on such 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 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 Notes will be redeemable and repayable, at any time in whole, or from time to time in part, at a price equal to 100% of the principal amount of the Notes to be redeemed, plus accrued interest on the Notes to be redeemed to the date of redemption.

The Notes are fully and unconditionally guaranteed on a senior unsecured basis by each of our wholly owned subsidiaries (the Subsidiary Guarantors). The Subsidiary Guarantors guarantees will be released if the Subsidiary Guarantors are released from their obligations under our RCF.

The Notes indenture contains customary events of default including, among others, (i) default in any payment of interest on any debt securities when due that continues for 30 days; (ii) default in payment, when due, of principal of or premium, if any, on the Notes at maturity; and (iii) certain events of bankruptcy or insolvency with respect to the Partnership. The indenture governing the Notes also contains covenants that limit, among other things, our ability, as well as that of the Subsidiary Guarantors 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, 2011, we were in compliance with all covenants under the Notes.

Note payable to Anadarko. In December 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. We have the option, at any time, to repay the outstanding principal amount in whole or in part.

The provisions of the five-year term loan agreement contain customary events of default, including (i) non-payment of principal when due or non-payment of interest or other amounts within three business days of when due, (ii) certain events of bankruptcy or insolvency with respect to the Partnership and (iii) a change of control. At December 31, 2011, we were in compliance with all covenants under this agreement.

Revolving credit facility. In March 2011, we 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 our $450.0 million credit facility, which was originally entered into in October 2009. 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%, plus applicable margins currently ranging from 0.30% to 0.90%. We are also 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 RCF contains covenants that limit, among other things, our, and certain of our subsidiaries , ability to incur additional indebtedness, grant certain liens, merge, consolidate or allow any material change in the character of our business, sell all or substantially all of our assets, make certain transfers, enter into certain affiliate transactions, make distributions or other payments other than distributions of available cash under certain conditions and use proceeds other than for partnership purposes. The RCF also contains various customary covenants, customary events of default and certain financial tests as of the end of each quarter, including a maximum consolidated leverage ratio (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 (Consolidated EBITDA) 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, and a minimum consolidated interest coverage ratio (which is defined as the ratio of Consolidated EBITDA for the most recent four consecutive fiscal quarters to consolidated interest expense for such period) of 2.0 to 1.0.

All amounts due under the RCF are unconditionally guaranteed by our wholly owned subsidiaries. We will no longer be required to comply with the minimum consolidated interest coverage ratio, as well as the subsidiary guarantees and certain of the aforementioned covenants, if we obtain two of the following three ratings: BBB- or better by Standard & Poor s, Baa3 or better by Moody s Investors Service, or BBB- or better by Fitch Ratings. As of December 31, 2011, no amounts were outstanding under the RCF, and $800.0 million was available for borrowing. At December 31, 2011, we were in compliance with all covenants under the RCF.

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 statement on file with the U.S. Securities and Exchange Commission.

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

We 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 gas, NGLs and condensate to Anadarko.

We expect our exposure to concentrated risk of non-payment or non-performance to continue for as long as we remain substantially dependent on Anadarko for our revenues. Additionally, we are exposed to credit risk on the note receivable from Anadarko, which was issued concurrently with the closing of our 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, its note payable to us, the omnibus agreement, the services and secondment agreement, contribution agreements or the commodity price swap agreements.

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CONTRACTUAL OBLIGATIONS

The following is a summary of our contractual cash obligations as of December 31, 2011. 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 2012.

	00000	00000	00000	00000	00000	00000	00000
				Obligations by Period			
thousands	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**
Long-term debt							
Principal	$	$ 175,000	$	$	$	$ 500,000	$ 675,000
Interest	31,810	32,043	26,875	26,875	26,875	119,967	264,445
Asset retirement obligations	875			931	470	57,687	59,963
Capital expenditures	30,197						30,197
Credit facility fees	2,005	2,000	2,000	2,000	460		8,465
Environmental obligations	1,533	516	330	140	140	286	2,945
Operating leases	224	200	168	168	168	103	1,031
Total	**$ 66,644**	**$ 209,759**	**$ 29,373**	**$ 30,114**	**$ 28,113**	**$ 678,043**	**$ 1,042,046**

Debt and credit facility fees. For additional information on notes payable and 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.

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 our 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.

In December 2011, we entered into a contribution agreement with Anadarko for the acquisition of a 100% interest in Mountain Gas Resources, LLC, which is discussed further in *Note 12. Subsequent Event* 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.

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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, goodwill, 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 approximately 21 years. If the depreciable lives of our assets were reduced by 10%, we estimate that annual depreciation expense would increase by approximately $11.0 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.

In assessing long-lived assets for impairments, 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.

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Impairments of 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 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 on the acquisition date. We evaluate whether goodwill has been impaired annually, as of October 1, or more often as facts and circumstances warrant. 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, 2011, was $59.3 million for the gathering and processing reporting unit and $4.8 million for the transportation reporting unit. Accounting standards require that goodwill be assessed for impairment at the reporting unit level. Goodwill impairment assessment is a two-step process. Step one focuses on identifying a potential impairment by comparing the fair value of the reporting unit with the carrying amount of the reporting unit. If the fair value of the reporting unit exceeds its carrying amount, no further action is required. However, if the carrying amount of the reporting unit exceeds its fair value, goodwill is written down to the implied fair value of the goodwill through a charge to operating expense based on a hypothetical purchase price allocation.

Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of reporting units for purposes of performing the goodwill impairment test. Management uses information available to make these fair value estimates, including market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA). Specifically, management estimates fair value by applying an estimated multiple to projected 2012 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 that the fair value of each reporting unit substantially exceeded the carrying value of the reporting unit. Therefore, no goodwill impairment was indicated and no goodwill impairment has been recognized in these consolidated financial statements.

Impairments of intangible assets. Our intangible asset balance at December 31, 2011, represents the fair value, net of amortization, of the contracts assumed by the Partnership in connection with the Platte Valley acquisition in February 2011. These long-term contracts, which dedicate certain customers field production to the acquired gathering and processing system, provide an extended commercial relationship with the existing customers whereby we will have the opportunity to gather and process future production from the customers acreage. Customer relationships are amortized on a straight-line basis over 50 years, which is the estimated productive life of the reserves covered by the underlying acreage ultimately expected to be produced and gathered or processed through the Partnership s assets subject to current contractual arrangements.

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 the respective asset may not be recoverable. Impairments exist when an asset s carrying amount exceeds estimates of the undiscounted cash flows expected to result from the use and eventual disposition of the tested 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 tested 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 operating expense. No intangible asset impairment has been recognized in connection with these assets.

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Fair value. Management estimates fair value in performing impairment tests for long-lived assets and goodwill as well as for the initial measurement of asset retirement obligations and the initial recognition of environmental obligations assumed in third-party acquisitions. When 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 valuation approach depending on the quality of information available to support management s assumptions. The income approach utilizes 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 utilizes 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

Recently issued accounting standard not yet adopted. In September 2011, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit s fair value is not required unless, as a result of the qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective prospectively beginning January 1, 2012. Adoption of this ASU will have no impact on our consolidated financial statements.

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 fixed-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* and *Note 12. Subsequent Event* 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% change in natural gas or NGL prices to have a material direct impact on our operating income, financial condition or cash flows for the next twelve months, excluding the effect of natural gas imbalances described below.

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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 2010 and in 2011 were low compared to historic rates. Only our RCF carries interest at variable rates based on LIBOR, and we did not have an outstanding balance as of December 31, 2011. If interest rates rise, our future financing costs could increase if we incur borrowings under our RCF.

We entered into a forward-starting interest-rate swap agreement in March 2011 to mitigate the risk of rising interest rates prior to the issuance of the Notes. In May 2011, we issued the Notes and terminated the swap agreement, realizing a loss of $1.9 million, which is included in other expense, net on our consolidated statements of income. For the year ended December 31, 2011, a 10% change in LIBOR would have resulted in a nominal change in net income.

We may incur additional 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

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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, 2011. This assessment was based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2011 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, 2011.

/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, 2012

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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, 2011, based on criteria established in *Internal Control Integrated Framework* 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, 2011, based on criteria established in *Internal Control Integrated Framework* 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, 2011 and 2010, 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, 2011, and our report dated February 28, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 28, 2012

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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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, 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, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2012 expressed an unqualified opinion on the effectiveness of the Partnership s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 28, 2012

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WESTERN GAS PARTNERS, LP

CONSOLIDATED STATEMENTS OF INCOME

thousands except per-unit amounts	Year Ended December 31, 2011	2010 [1]	2009 [1]
Revenues affiliates			
Gathering, processing and transportation of natural gas and natural gas liquids	**$ 216,445**	$ 189,486	$ 178,771
Natural gas, natural gas liquids and condensate sales	**276,746**	232,686	222,828
Equity income and other, net	**12,427**	8,451	8,925
Total revenues affiliates	**505,618**	430,623	410,524
Revenues third parties			
Gathering, processing and transportation of natural gas and natural gas liquids	**70,524**	44,222	47,628
Natural gas, natural gas liquids and condensate sales	**84,836**	26,134	30,790
Other, net	**3,102**	4,222	1,604
Total revenues third parties	**158,462**	74,578	80,022
Total revenues	**664,080**	505,201	490,546
Operating expenses			
Cost of product [2]	**247,302**	157,049	164,072
Operation and maintenance [2]	**101,754**	85,407	89,535
General and administrative [2]	**35,388**	25,305	28,569
Property and other taxes	**15,695**	13,454	13,566
Depreciation, amortization and impairments	**88,454**	73,791	66,802
Total operating expenses	**488,593**	355,006	362,544
Operating income	**175,487**	150,195	128,002
Interest income affiliates	**16,900**	16,900	16,900
Interest expense [3]	**(31,559)**	(21,951)	(10,195)
Other income (expense), net	**(1,624)**	(2,123)	62
Income before income taxes	**159,204**	143,021	134,769
Income tax expense	**2,161**	9,142	17,260
Net income	**157,043**	133,879	117,509
Net income attributable to noncontrolling interests	**14,103**	11,005	10,260
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249
Limited partners interest in net income:			
Net income attributable to Western Gas Partners, LP	**$ 142,940**	$ 122,874	$ 107,249
Pre-acquisition net (income) loss allocated to Parent	**(2,781)**	(8,743)	(35,841)
General partner interest in net (income) loss [4]	**(8,599)**	(3,067)	(1,428)
Limited partners interest in net income [4]	**$ 131,560**	$ 111,064	$ 69,980

Net income per common unit basic and diluted	**$**	**1.64**	$	1.66	$	1.25
Net income per subordinated unit basic and diluted[5]	**$**	**1.28**	$	1.61	$	1.24

(1) Financial information has been revised to include the financial position and results attributable to the Bison assets. See *Note 2*.

(2) Cost of product includes product purchases from Anadarko (as defined in *Note 1)* of $75.9 million, $63.4 million and $69.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. Operation and maintenance includes charges from Anadarko of $44.1 million, $38.6 million and $35.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. General and administrative includes charges from Anadarko of $28.1 million, $19.5 million and $22.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. See *Note 5*.

(3) Includes affiliate (as defined in *Note 1)* interest expense of $6.1 million, $10.1 million and $9.3 million for years ended December 31, 2011, 2010 and 2009, respectively. See *Note 10*.

(4) Represents net income for periods including and subsequent to the acquisition of the Partnership assets (as defined in *Note 1*). See also *Note 4*.

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

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, 2011	2010 [1]
ASSETS		
Current assets		
Cash and cash equivalents	**$ 226,559**	$ 27,074
Accounts receivable, net [2]	**22,197**	10,890
Other current assets [3]	**6,794**	5,220
Total current assets	**255,550**	43,184
Note receivable Anadarko	**260,000**	260,000
Plant, property and equipment		
Cost	**2,223,800**	1,815,049
Less accumulated depreciation	**452,866**	369,006
Net property, plant and equipment	**1,770,934**	1,446,043
Goodwill and other intangible assets	**116,994**	64,136
Equity investments	**39,978**	40,406
Other assets	**8,164**	2,361
Total assets	**$ 2,451,620**	$ 1,856,130
LIABILITIES, EQUITY AND PARTNERS CAPITAL		
Current liabilities		
Accounts and natural gas imbalance payables [4]	**$ 25,744**	$ 15,282
Accrued ad valorem taxes	**7,882**	5,986
Income taxes payable	**495**	160
Accrued liabilities [5]	**36,973**	24,436
Total current liabilities	**71,094**	45,864
Long-term debt third parties	**494,178**	299,000
Note payable Anadarko	**175,000**	175,000
Asset retirement obligations and other	**63,642**	61,840
Total long-term liabilities	**732,820**	535,840
Total liabilities	**803,914**	581,704
Equity and partners capital		
Common units (90,140,999 and 51,036,968 units issued and outstanding at December 31, 2011 and 2010, respectively)	**1,495,253**	810,717
Subordinated units (zero and 26,536,306 units issued and outstanding at December 31, 2011 and 2010, respectively) [6]		282,384
General partner units (1,839,613 and 1,583,128 units issued and outstanding at December 31, 2011 and 2010, respectively)	**31,729**	21,505
Parent net investment		69,358
Total partners capital	**1,526,982**	1,183,964

Noncontrolling interests	**120,724**	90,462
Total equity and partners capital	**1,647,706**	1,274,426
Total liabilities, equity and partners capital	**$ 2,451,620**	$ 1,856,130

(1) Financial information has been revised to include the financial position and results attributable to the Bison assets. See *Note 2*.

(2) Accounts receivable, net includes amounts receivable from affiliates (as defined in *Note 1*) of zero and $1.8 million as of December 31, 2011 and 2010, respectively.

(3) Other current assets includes natural gas imbalance receivables from affiliates of $0.5 million and zero as of December 31, 2011 and 2010, respectively.

(4) Accounts and natural gas imbalance payables includes amounts payable to affiliates of $5.9 million and $1.5 million as of December 31, 2011 and 2010, respectively.

(5) Accrued liabilities include amounts payable to affiliates of $0.3 million and $0.6 million as of December 31, 2011 and 2010, respectively.

(6) 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 STATEMENTS OF EQUITY AND PARTNERS CAPITAL

		Partners Capital				
thousands	Parent Net Investment	Common Units	Subordinated Units	General Partner Units	Noncontrolling Interests	Total
Balance at December 31, 2008 [1]	$ 518,622	$ 368,050	$ 275,917	$ 10,988	$ 66,016	$ 1,239,593
Net income	35,841	37,035	32,945	1,428	10,260	117,509
Issuance of common and general partner units, net of offering expenses		120,080		2,459		122,539
Contributions from noncontrolling interest owners	20,544				19,718	40,262
Distributions to noncontrolling interest owners	(2,926)				(5,072)	(7,998)
Distributions to unitholders		(36,025)	(32,640)	(1,401)		(70,066)
Acquisition from affiliates	(112,744)	11,068		225		(101,451)
Net pre-acquisition contributions from (distributions to) Parent	(6,088)					(6,088)
Non-cash equity-based compensation and other	2,354	(2,978)	349	27		(248)
Balance at December 31, 2009 [1]	$ 455,603	$ 497,230	$ 276,571	$ 13,726	$ 90,922	$ 1,334,052
Net income	8,743	68,410	42,654	3,067	11,005	133,879
Issuance of common and general partner units, net of offering expenses		338,483		7,320		345,803
Contributions from noncontrolling interest owners					2,053	2,053
Distributions to noncontrolling interest owners					(13,222)	(13,222)
Distributions to unitholders		(55,108)	(36,885)	(2,201)		(94,194)
Acquisitions from affiliates	(684,487)	(49,662)		(631)		(734,780)
Net pre-acquisition contributions from (distributions to) Parent	73,816					73,816
Contribution of other assets from Parent		10,500		215		10,715
Elimination of net deferred tax liabilities	214,464					214,464
Non-cash equity-based compensation and other	1,219	864	44	9	(296)	1,840
Balance at December 31, 2010 [1]	$ 69,358	$ 810,717	$ 282,384	$ 21,505	$ 90,462	$ 1,274,426
Net income	**2,781**	**110,542**	**21,018**	**8,599**	**14,103**	**157,043**
Conversion of subordinated units to common units [2]		**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 Parent		**9,472**		**194**		**9,666**
Net pre-acquisition contributions from (distributions to) Parent	**(1,545)**					**(1,545)**
Elimination of net deferred tax liabilities	**22,072**					**22,072**
Non-cash equity-based compensation and other		**(267)**		**(47)**		**(314)**
Balance at December 31, 2011	**$**	**$ 1,495,253**	**$**	**$ 31,729**	**$ 120,724**	**$ 1,647,706**

(1) Financial information has been revised to include the financial position and results attributable to the Bison assets. See *Note 2*.
(2) 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 STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
thousands	**2011**	**2010** [1]	**2009** [1]
Cash flows from operating activities			
Net income	**$ 157,043**	$ 133,879	$ 117,509
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairments	**88,454**	73,791	66,802
Deferred income taxes	**5,351**	15,218	(4,070)
Changes in assets and liabilities:			
(Increase) decrease in accounts receivable, net	**(1,091)**	(269)	1,795
Increase (decrease) in accounts and natural gas imbalance payables and accrued liabilities, net	**23,342**	10,785	(20,071)
Change in other items, net	**(2,685)**	(6,987)	1,805
Net cash provided by operating activities	**270,414**	226,417	163,770
Cash flows from investing activities			
Capital expenditures	**(135,495)**	(130,149)	(102,717)
Acquisitions from affiliates	**(28,837)**	(734,780)	(101,451)
Acquisitions from third parties	**(301,957)**	(18,047)	
Investments in equity affiliates	**(93)**	(310)	(382)
Proceeds from sale of assets to affiliates	**382**	2,805	
Proceeds from sale of assets to third parties	**500**	2,825	
Net cash used in investing activities	**(465,500)**	(877,656)	(204,550)
Cash flows from financing activities			
Borrowings, net of debt issuance costs	**1,055,939**	660,000	101,451
Repayments of debt	**(869,000)**	(361,000)	(101,451)
Revolving credit facility issuance costs		(12)	(4,263)
Proceeds from issuance of common and general partner units, net of offering expenses	**335,317**	345,803	122,539
Distributions to unitholders	**(140,118)**	(94,194)	(70,066)
Contributions from noncontrolling interest owners	**33,637**	2,053	40,262
Distributions to noncontrolling interest owners	**(17,478)**	(13,222)	(7,998)
Net contributions from (distributions to) Parent	**(3,726)**	68,901	(5,784)
Net cash provided by financing activities	**394,571**	608,329	74,690
Net increase (decrease) in cash and cash equivalents	**199,485**	(42,910)	33,910
Cash and cash equivalents at beginning of period	**27,074**	69,984	36,074
Cash and cash equivalents at end of period	**$ 226,559**	$ 27,074	$ 69,984
Supplemental disclosures			
Elimination of net deferred tax liabilities	**$ 22,072**	$ 214,464	$
Contribution of assets (to) from Parent	**$ (66)**	$ 7,598	$
Increase (decrease) in accrued capital expenditures	**$ 5,507**	$ 6,453	$ (13,135)
Interest paid	**$ 25,828**	$ 16,497	$ 9,372
Interest received	**$ 16,900**	$ 16,900	$ 16,900

Taxes paid	**$**	**190**	$	507	$

(1) Financial information has been revised to include the financial position and results attributable to the Bison assets. See *Note 2*.

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 (the Partnership), 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 to become publicly traded in 2008. As of December 31, 2011, the Partnership s assets include eleven gathering systems, seven natural gas treating facilities, seven natural gas processing facilities, one NGL pipeline, one interstate pipeline, and interests in Fort Union Gas Gathering, LLC (Fort Union) and White Cliffs Pipeline, LLC (White Cliffs), which are accounted for under the equity method. The Partnership s assets are located in East and West Texas, the Rocky Mountains (Colorado, Utah and Wyoming), and the Mid-Continent (Kansas and Oklahoma). The Partnership is 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.

For purposes of these consolidated financial statements, the Partnership refers to Western Gas Partners, LP and its subsidiaries. The Partnership s general partner is Western Gas Holdings, LLC (the general partner or GP), a wholly owned subsidiary of Anadarko Petroleum Corporation. Anadarko or Parent refers to Anadarko Petroleum Corporation and its consolidated subsidiaries, excluding the Partnership and the general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union and White Cliffs.

Basis of presentation. The accompanying consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles in the United States (GAAP), and certain amounts in prior periods have been reclassified to conform to the current presentation. The consolidated financial statements include the accounts of the Partnership and entities in which it holds a controlling financial interest, and all significant intercompany transactions have been eliminated. Investments in non-controlled entities over which the Partnership exercises significant influence are accounted for under the equity method. The Partnership proportionately consolidates its 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, as amended and restated (the Chipeta LLC agreement) (see *Notes 2 and 3*). As of December 31, 2011, Chipeta is owned 51% by the Partnership, 24% by Anadarko and 25% by a third-party member. The interests in Chipeta, held by Anadarko and the third-party member, are reflected as noncontrolling interests in the Partnership s consolidated financial statements for all periods presented.

Presentation of Partnership assets. References to the Partnership assets refer collectively to the assets owned by the Partnership as of December 31, 2011. Because of Anadarko s control of the Partnership through its ownership of the general partner, each acquisition of Partnership assets through December 31, 2011, except for the acquisitions of the Platte Valley assets and the 9.6% interest in White Cliffs from third parties, was considered a transfer of net assets between entities under common control (see *Note 2*). As a result, after each acquisition of assets from Anadarko, the Partnership is required to revise its financial statements to include the activities of the Partnership assets as of the date of common control.

The consolidated financial statements for periods prior to the Partnership s acquisition of the Partnership assets 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 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 or subordinated unit.

Use of estimates. In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the amounts reported in the consolidated financial statements and the notes thereto. Management evaluates its estimates and related assumptions regularly, utilizing historical experience and other methods considered reasonable under the 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 Partnership s business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision 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 utilizes the cost, income, or market valuation approach depending on the quality of information available to support management s assumptions.

The fair value of debt is the estimated amount the Partnership would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market rate of interest at the balance sheet date. Fair values are based on quoted market prices for identical instruments, if available, or average valuations of similar debt instruments at the balance sheet date. 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 debt on a customer-by-customer basis for its third-party accounts receivable and may establish credit limits for significant third-party customers. At December 31, 2011 and 2010, third-party accounts receivable are shown net of the associated bad-debt reserve of $17,000.

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. 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, 2011, natural gas imbalance receivables and payables were approximately $2.3 million and $3.1 million, respectively. As of December 31, 2010, natural gas imbalance receivables and payables were approximately $0.1 million and $2.6 million, respectively. Changes in natural gas imbalances are reported in equity income and other, net or cost of product in the consolidated statements of income.

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.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 Partnership assets acquired by the Partnership 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. The Partnership capitalizes all construction-related direct labor and material costs. 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 over the asset s estimated useful life using the straight-line method or half-year convention method, based on estimated useful lives and salvage values of assets. 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. When assets are placed into service, the Partnership makes estimates with respect to useful lives and salvage values that the Partnership believes are reasonable. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts.

The Partnership 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.

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 and other intangible assets. 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 of an entity over the estimated fair value of the identifiable assets acquired and liabilities assumed by Anadarko. Accordingly, the Partnership s goodwill balance does not reflect, and in some cases is significantly different than, the difference between the consideration the Partnership paid for its acquisitions from Anadarko and the fair value of the net assets on the acquisition date. The Partnership s consolidated balance sheets as of December 31, 2011 and 2010, include goodwill of $64.1 million, none of which is deductible for tax purposes.

The Partnership evaluates goodwill for impairment annually, as of October 1, or more often as facts and circumstances warrant. The first step in the goodwill impairment test is to compare the fair value of each reporting unit to which goodwill has been assigned to the carrying amount of net assets, including goodwill, of the respective reporting unit. The Partnership has allocated goodwill on its two reporting units: (i) gathering and processing and (ii) transportation. If the carrying amount of the reporting unit exceeds its fair value, step two in the goodwill impairment test requires goodwill to be written down to its implied fair value through a charge to operating expense based on a hypothetical purchase price allocation. No goodwill impairment has been recognized in these consolidated financial statements. The carrying value of goodwill after such an impairment would represent a Level 3 fair value measurement.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The Partnership assesses intangible assets, as described in *Note 8,* for impairment together with related underlying long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. 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 operating expense. No intangible asset impairment has been recognized in connection with these assets.

Equity-method investments. The following table presents the activity in the Partnership s investments in equity of Fort Union and White Cliffs:

	0000	**0000**
	Equity Investments	
thousands	**Fort Union** [1]	**White Cliffs** [2]
Balance at December 31, 2009	$ 20,060	$ 1,284
Investment earnings, net of amortization	5,723	917
Contributions	310	
Distributions	(4,665)	(1,270)
Acquisition of additional 9.6% interest from third party		18,047
Balance at December 31, 2010	$ 21,428	$ 18,978
Investment earnings, net of amortization	**6,067**	**4,023**
Contributions		**93**
Distributions	**(5,227)**	**(5,384)**
Balance at December 31, 2011	**$ 22,268**	**$ 17,710**

(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 and became operational in June 2009. 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.

The investment balance at December 31, 2011, includes $2.7 million for the purchase price allocated to the investment in Fort Union in excess of the historic cost basis of Western Gas Resources, Inc. (entity that owned Fort Union, which Anadarko acquired in August 2006). This excess balance is attributable to the difference between the fair value and book value of Fort Union s gathering and treating facilities and is being amortized over the remaining estimated useful life of those facilities. Each of the joint venture members has pledged its respective equity interest to the administrative agent of Fort Union s credit agreement.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The White Cliffs investment balance at December 31, 2011, is $10.4 million less than the Partnership s underlying equity in White Cliffs net assets as of December 31, 2011, 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.

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.

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 accreted through accretion expense to its expected settlement value. 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*.

Environmental expenditures. The Partnership expenses environmental expenditures related to conditions caused by past operations that do not generate current or future revenues. Environmental expenditures 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 consist of natural gas, NGLs and crude oil gathering and processing systems, treating facilities, pipelines and related plants and equipment.

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 percent-of-proceeds contracts, revenue is recognized when the natural gas, NGLs or condensate are sold and the related purchases are recorded as a percentage of the product sale.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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 gas 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 gas. 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 as liquids than as a component of the natural gas stream. 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. See *Note 11* for discussion of the Partnership s pending rate case with the FERC.

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

Equity-based compensation. Phantom unit awards are granted under the Western Gas Partners, LP 2008 Long-Term Incentive Plan (the LTIP). The LTIP was adopted by the general partner of the Partnership and permits the issuance of up to 2,250,000 units, of which 2,160,848 units remain available for future issuance as of December 31, 2011. Upon vesting of each phantom unit, 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 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 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) Western Gas Holdings, LLC Equity Incentive Plan, as amended and restated (the Incentive Plan) and (ii) the Anadarko Petroleum Corporation 1999 Stock Incentive Plan and the Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan (Anadarko s plans are referred to collectively as the Anadarko Incentive Plans).

Under the Incentive Plan, participants are granted Unit Value Rights (UVRs), Unit Appreciation Rights (UARs) and Dividend Equivalent Rights (DERs). UVRs and UARs granted under the Incentive Plan in 2011 and 2010 were collectively valued at $634.00 per unit and $215.00 per unit as of December 31, 2011 and 2010, respectively. The UVRs and UARs either vest ratably over three years or vest in two equal installments on the second and fourth anniversaries of the grant date, or earlier in connection with certain other events. Upon the occurrence of a UVR vesting event, each participant will receive a lump-sum cash payment (net of any applicable withholding taxes) for each UVR. The UVRs may not be sold or transferred except to the general partner, Anadarko or any of its affiliates. Upon the occurrence of a UAR vesting event, each participant will receive a lump-sum cash payment (net of any applicable withholding taxes) for each UAR that is exercised prior to (i) the 90th day after a participant s voluntary termination, or (ii) the 10th anniversary of the grant date, whichever occurs first. DERs granted under the Incentive Plan vest upon the occurrence of certain events, become payable no later than 30 days subsequent to vesting and expire 10 years from the date of grant.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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. For equity-based awards issued under the Incentive Plan and ultimately settled in cash, the fair value of the relevant equity grant is 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. Equity-based compensation expense attributable to grants made under the Incentive Plan will impact the Partnership s cash flows from operating activities only to the extent cash payments are made to Incentive Plan participants who provided services to us pursuant to the omnibus agreement. Equity-based compensation granted under the Anadarko Incentive Plans does not impact the Partnership s cash flows from operating activities. 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. Federal and state income tax expense was recorded prior to the Partnership s acquisition of the Partnership assets. In addition, deferred federal and state income taxes are recorded on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases with respect to the Partnership assets prior to the Partnership s acquisition; and deferred state income taxes are recorded with respect to the Partnership assets including and subsequent to acquisition. The recognition of deferred federal and state tax assets prior to the Partnership s acquisition of the Partnership assets was based on management s belief that it was more likely than not that the results of future operations would generate sufficient taxable income to realize the deferred tax assets. For periods including or subsequent to the Partnership s acquisition of the Partnership assets, the Partnership is only subject to Texas margin tax; therefore, deferred federal income tax assets and liabilities with respect to the Partnership assets for periods including and subsequent to the Partnership s acquisitions are no longer recognized by the Partnership.

For periods including 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 standard for uncertain tax positions defines the criteria an individual tax position must meet for any part of the benefit of that position to be recognized in the financial statements. The Partnership has no material uncertain tax positions at December 31, 2011 or 2010.

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WESTERN GAS PARTNERS, LP

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 partnership units and incentive distribution rights (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 for periods including and subsequent to the Partnership s 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. 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*.

Recently issued accounting standard not yet adopted. In September 2011, the Financial Accounting Standards Board issued an Accounting Standards Update (ASU) that permits an initial assessment of qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount for goodwill impairment testing purposes. Thus, determining a reporting unit s fair value is not required unless, as a result of the qualitative assessment, it is more likely than not that the fair value of the reporting unit is less than its carrying amount. This ASU is effective prospectively beginning January 1, 2012. Adoption of this ASU will have no impact on the Partnership s consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. ACQUISITIONS

The following table presents the acquisitions completed by the Partnership during the years ended December 31, 2011, 2010 and 2009, and details the funding for those acquisitions through borrowings, cash on hand and/or the issuance of Partnership equity:

thousands except unit and percent amounts	00000 **Acquisition Date**	00000 **Percentage Acquired**	00000 **Borrowings**	00000 **Cash On Hand**	00000 **Common Units Issued**	00000 **GP Units Issued**
Chipeta (1)	07/01/09	51%	$ 101,451	$ 4,638	351,424	7,172
Granger (2)	01/29/10	100%	210,000	31,680	620,689	12,667
Wattenberg (3)	08/02/10	100%	450,000	23,100	1,048,196	21,392
White Cliffs (4)	09/28/10	10%		38,047		
Platte Valley (5)	**02/28/11**	**100%**	**303,000**	**602**		
Bison (6)	**07/08/11**	**100%**		**25,000**	**2,950,284**	**60,210**

(1) The assets acquired from Anadarko include a 51% membership interest in Chipeta, together with an associated NGL pipeline. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah. Chipeta owns a natural gas processing plant with two processing trains: a refrigeration unit and a cryogenic unit. In addition, in November 2009, Chipeta acquired the Natural Buttes plant including a compressor station and processing plant from a third party for $9.1 million, of which $4.5 million was contributed by the noncontrolling interest owners to fund their proportionate share. The 51% membership interest in Chipeta and associated NGL pipeline are referred to collectively as the Chipeta assets and the acquisition is referred to as the Chipeta acquisition.

(2) The assets acquired from Anadarko include (i) the Granger gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of cryogenic trains, a refrigeration train, an NGLs fractionation facility and ancillary equipment. These assets, located in southwestern Wyoming, are referred to collectively as the Granger assets and the acquisition as the Granger acquisition.

(3) The assets acquired from Anadarko include the Wattenberg gathering system and related facilities, including the Fort Lupton processing plant. These assets, located in the Denver-Julesburg Basin, north and east of Denver, Colorado, are referred to collectively as the Wattenberg assets and the acquisition as the Wattenberg acquisition.

(4) White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma, which became operational in June 2009. The Partnership s acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko combined with the acquisition of an additional 9.6% interest in White Cliffs from a third party, are referred to collectively as the White Cliffs acquisition. The Partnership s interest in White Cliffs is referred to as the White Cliffs investment.

(5) The assets acquired from a third party include (i) a natural gas gathering system and related compression and other ancillary equipment, and (ii) cryogenic gas processing facilities. These assets, located in the Denver-Julesburg Basin, are referred to collectively as the Platte Valley

assets and the acquisition as the Platte Valley acquisition. See further information below, including the final allocation of the purchase price in August 2011.

(6) 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 and the acquisition as the Bison acquisition. The Bison assets are the only treating and delivery point into the third-party-owned Bison pipeline. Anadarko began construction of the Bison assets in 2009 and placed them in service in June 2010. See further information below.

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WESTERN GAS PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2. ACQUISITIONS (CONTINUED)

Platte Valley acquisition. The Platte Valley acquisition has been accounted for under the acquisition method of accounting. The Platte Valley assets and liabilities were recorded in the consolidated balance sheet at their estimated fair values as of the acquisition date. Results of operations attributable to the Platte Valley assets were included in the Partnership s consolidated statements of income beginning on the acquisition date in the first quarter of 2011.

The table below reflects the final allocation of the purchase price, including a $1.6 million adjustment to intangible assets recorded in August 2011, to the assets acquired and liabilities assumed in the Platte Valley acquisition:

thousands	
Property, plant and equipment	**$ 264,521**
Intangible assets	**53,754**
Asset retirement obligations and other liabilities	**(16,318)**
Total purchase price	**$ 301,957**

The purchase price allocation is based on an assessment of the fair value of the assets acquired and liabilities assumed in the Platte Valley acquisition, after consideration of post-closing purchase price adjustments. 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. For more information regarding the intangible assets presented in the table above, see *Note 8.*

The following table presents the pro forma condensed financial information of the Partnership as if the Platte Valley acquisition had occurred on January 1, 2011:

thousands except per-unit amount	**Year Ended December 31, 2011**
Revenues	**$ 680,119**
Net income	**159,769**