Western Gas Partners LP
Form 10-K
February 24, 2011

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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, 2010

Or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission file number: 001-34046

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

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

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

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

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

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

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

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

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

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

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

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

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

The aggregate market value of the Partnership s common units representing limited partner interests held by non-affiliates of the registrant was approximately $703.1 million on June 30, 2010 based on the closing price as reported on the New York Stock Exchange.

At February 18, 2011, there were 51,036,968 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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DEFINITIONS

As generally used within the energy industry and in this annual report, 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/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°F) 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.

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

LTD: Long tons per day.

MMBtu: One million British thermal units.

MMBtu/d: One million British thermal units per day.

MMcf/d: One million cubic feet per day. All volumes presented herein are based on a standard pressure base of 14.73 pounds per square inch, absolute.

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.

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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WESTERN GAS PARTNERS, LP

PART I

Items 1 and 2. *Business and Properties*

GENERAL OVERVIEW

Western Gas Partners, LP is a growth-oriented Delaware master limited partnership, or MLP, organized by Anadarko Petroleum Corporation in 2008 to own, operate, acquire and develop midstream energy assets. Our common units are publicly traded and listed on the New York Stock Exchange, or NYSE, under the symbol WES. With midstream assets in East and West Texas, the Rocky Mountains and the Mid-Continent, we are engaged in the business of gathering, processing, compressing, treating and transporting natural gas, condensate, natural gas liquids, or NGLs, and crude oil for Anadarko, as defined below, and other producers and customers.

Unless the context clearly indicates otherwise, references in this report to the Partnership, we, our, us or like terms, when used in the present tense or prospective context, refer to Western Gas Partners, LP and its consolidated subsidiaries. References in this report to the Partnership, we, our, us or like terms, when used in the historical conte refer (i) to the business and operations of Anadarko Gathering Company LLC and Pinnacle Gas Treating LLC from their inception through the closing date of our initial public offering and (ii) to Western Gas Partners, LP and its subsidiaries thereafter, combined with (a) the business and operations of MIGC LLC, the Powder River assets and the Granger assets, as described in *Acquisitions Powder River acquisition* and *Acquisitions Granger acquisition* below, since August 23, 2006; (b) the business and operations of the Chipeta assets and Wattenberg assets, as described in *Acquisitions Chipeta acquisition* and *Acquisitions Wattenberg acquisition* below, since August 10, 2006; and (c) the financial results of Anadarko Wattenberg Company, LLC, or AWC, including the 0.4% interest in White Cliffs Pipeline, LLC, or White Cliffs, since January 29, 2007, as described in *Acquisitions White Cliffs acquisition* below.

Anadarko or Parent refers to Anadarko Petroleum Corporation (NYSE: APC) and its consolidated subsidiaries, excluding the Partnership and Western Gas Holdings, LLC, our general partner. Affiliates refers to wholly owned and partially owned subsidiaries of Anadarko, excluding the Partnership, and also refers to Fort Union Gas Gathering, L.L.C., or Fort Union, and 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.

Approximately two-thirds of our services are provided 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.

We believe that one of our principal strengths is our relationship with Anadarko. Over 74% of our total natural gas gathering, processing and transportation throughput during the year ended December 31, 2010 was comprised of natural gas production owned or controlled by Anadarko. In addition and solely with respect to the Wattenberg gathering system and the gathering systems included in our initial assets, as described under *Acquisitions* below, 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.

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, or the SEC, under the Securities Exchange Act of 1934, or the Exchange Act. From time-to-time, we may also file registration and related statements pertaining to equity or debt offerings. We provide access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing with the SEC, on our Internet site located at *www.westerngas.com*. The public may also read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The public may also obtain such reports from the SEC s Internet website at *www.sec.gov*.

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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.

OUR ASSETS AND AREAS OF OPERATION

As of December 31, 2010, our assets consist of ten gathering systems, six natural gas treating facilities, six natural gas processing facilities, one NGL pipeline, one interstate pipeline that is regulated by the Federal Energy Regulatory Commission, or FERC, and non-controlling interests in a gas gathering system and a crude oil pipeline. Our assets are located in East and West Texas, the Rocky Mountains and the Mid-Continent. The following table provides information regarding our assets by geographic region as of and for the year ended December 31, 2010:

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	4,302	3,591	221,541	1,527	1,123
	Transportation	782	15	29,696		163
Mid-Continent	Gathering	1,953	1,549	91,105		109
East Texas	Gathering and Treating	588	820	37,875	502	319
West Texas	Gathering	118	90	560		114
Total		7,743	6,065	380,777	2,029	1,828

(1) Throughput includes 100% of Chipeta system volumes, excluding NGL pipeline volumes measured in barrels; 50% of Newcastle system volumes; 14.81% of Fort Union s gross volumes; and excludes crude oil throughput measured in barrels attributable to White Cliffs.

Our operations are organized into a single operating segment which 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 annual report for disclosure of revenues, profits and total assets.

ACQUISITIONS

We have made the following acquisitions since our inception:

White Cliffs acquisition. In September 2010, we and Anadarko closed a series of related agreements through which we acquired a 10% member interest in White Cliffs. Specifically, the Partnership acquired Anadarko s 100% ownership interest in AWC for $20.0 million in cash. AWC owned a 0.4% interest in White Cliffs and held an option to increase its interest in White Cliffs. Also, in a series of concurrent transactions, AWC acquired an additional 9.6% interest in White Cliffs from a third party for $18.0 million in cash, subject to post-closing adjustments. White Cliffs owns a crude oil pipeline that originates in Platteville, Colorado and terminates in Cushing, Oklahoma and became operational in June 2009. The Partnership s acquisition of the 0.4% interest in White Cliffs and related purchase option from Anadarko is referred to as the AWC acquisition. The AWC acquisition and the acquisition of an additional 9.6% interest in White Cliffs were funded with cash on hand and are referred to collectively as the White Cliffs acquisition. The Partnership s interest in White Cliffs is referred to as the White Cliffs investment.

Wattenberg acquisition. In August 2010, we acquired certain midstream assets from Anadarko for (i) $473.1 million in cash, which was funded with $250.0 million of borrowings under an unsecured term loan, $200.0 million of borrowings under the Partnership s revolving credit facility and $23.1 million of cash on hand; as well as (ii) the issuance of 1,048,196 common units to Anadarko and 21,392 general partner units to our general partner. The assets acquired represent a 100% ownership interest in Kerr-McGee Gathering LLC, which owns 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.

Granger acquisition. In January 2010, we acquired the following assets from Anadarko: (i) the Granger gathering system, a 750-mile gathering system with related compressors and other facilities, and (ii) the Granger complex, consisting of two cryogenic trains with combined capacity of 200 MMcf/d, two refrigeration trains with combined capacity of 145 MMcf/d, a NGLs fractionation facility with capacity of 9,500 barrels per day, and ancillary equipment. We refer to these assets collectively as the Granger assets and to the acquisition as the Granger acquisition. The Granger acquisition was financed with $210.0 million of borrowings under the Partnership s revolving credit facility plus $31.7 million of cash on hand, as well as through the issuance of 620,689 common units to Anadarko and 12,667 general partner units to our general partner. In September 2010, we sold an idle refrigeration train at the Granger system to a third party for $2.4 million.

Chipeta acquisition. In July 2009, we acquired a 51% membership interest in Chipeta, together with an associated NGL pipeline, from Anadarko for consideration consisting of $101.5 million in cash, which was initially funded by a note from Anadarko, 351,424 common units and 7,172 general partner units. Chipeta owns a natural gas processing plant complex, which includes: a refrigeration unit completed in November 2007 with a design capacity of 240 MMcf/d and a 250 MMcf/d capacity cryogenic unit which was completed in April 2009. We refer to the 51% membership interest in Chipeta and associated NGL pipeline collectively as the Chipeta assets and the acquisition as the Chipeta acquisition. In November 2009, Chipeta closed its $9.1 million acquisition from a third party of a compressor station and processing plant, or the Natural Buttes plant, which was known as the Colorado Interstate Gas Company (CIG) 101 plant prior to the acquisition. The Natural Buttes plant is located in Uintah County, Utah and provides up to 180 MMcf/d of incremental refrigeration processing capacity.

Powder River acquisition. In December 2008, we acquired certain midstream assets from Anadarko, consisting of (i) a 100% ownership interest in the Hilight system, (ii) a 50% interest in the Newcastle system and (iii) a 14.81% limited liability company membership interest in Fort Union. We refer to these assets collectively as the Powder River assets and to the acquisition as the Powder River acquisition. Consideration for the Powder River acquisition consisted of $175.0 million in cash funded by a note from Anadarko, as well as 2,556,891 common units and 52,181 general partner units. The Powder River assets provide a combination of gathering, processing, compressing and treating services to customers in the Powder River Basin of Wyoming.

Initial assets acquisition. Concurrent with the May 2008 closing of our initial public offering (described below under *Equity Offerings*), Anadarko contributed the assets and liabilities of AGC, PGT and MIGC to us in exchange for a 2.0% general partner interest in the Partnership, 5,725,431 common units, 26,536,306 subordinated units and 100% of the incentive distribution rights, or IDRs. We refer to AGC, PGT and MIGC as our initial assets.

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Presentation of Partnership acquisitions. References to Partnership Assets refer collectively to the initial assets, Powder River assets, Chipeta assets, Natural Buttes plant, Granger assets, Wattenberg assets and White Cliffs investment. Unless otherwise noted, references to periods prior to our acquisition of the Partnership Assets and similar phrases refer to periods prior to May 2008 with respect to the initial assets, periods prior to December 2008 with respect to the Powder River assets, periods prior to July 2009 with respect to the Chipeta assets, periods prior to November 2009 with respect to the Natural Buttes plant, periods prior to January 2010 with respect to the Granger assets, periods prior to July 2010 with respect to the Wattenberg assets, and periods prior to September 2010 with respect to the White Cliffs investment. Reference to periods including and subsequent to our acquisition of the Partnership Assets and similar phrases refer to periods including and subsequent to May 2008 with respect to the initial assets, periods including and subsequent to December 2008 with respect to the Powder River assets, periods including and subsequent to July 2009 with respect to the Chipeta assets, periods subsequent to November 2009 with respect to the Natural Buttes plant, periods including and subsequent to January 2010 with respect to the Granger assets, periods including and subsequent to July 2010 with respect to the Wattenberg assets, and periods including and subsequent to September 2010 with respect to the White Cliffs investment.

Because Anadarko indirectly owns our general partner, each acquisition of Partnership Assets, except for the Natural Buttes plant and the acquisition of a 9.6% interest in White Cliffs from a third party, was considered a transfer of net assets between entities under common control. Accordingly, our consolidated financial statements include the financial results and operations of the Partnership Assets since the date of common control.

EQUITY OFFERINGS

Since its inception, the Partnership has completed the following public equity offerings:

November 2010 equity offering. On November 15, 2010, we closed a public offering of 7,500,000 common units at a price of $29.92 per unit. On November 22, 2010, we issued an additional 915,000 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the November 15 and November 22, 2010 issuances collectively as the November 2010 equity offering. In connection with the November 2010 equity offering, we also issued 171,734 general partner units to our general partner. Net proceeds from the November 2010 equity offering of approximately $246.7 million were primarily used to repay amounts outstanding under our revolving credit facility.

May 2010 equity offering. On May 18, 2010, we closed a public offering of 4,000,000 common units at a price of $22.25 per unit. On June 2, 2010, we issued an additional 558,700 common units to the public pursuant to the exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the May 18 and June 2, 2010 issuances collectively as the May 2010 equity offering. In connection with the May 2010 equity offering, we also issued 93,035 general partner units to our general partner. Net proceeds from the May 2010 equity offering of approximately $99.1 million were used to repay amounts outstanding under our revolving credit facility.

2009 equity offering. On December 9, 2009, we closed a public offering of 6,000,000 common units at a price of $18.20 per unit. On December 17, 2009, we issued an additional 900,000 common units to the public pursuant to the full exercise of the underwriters over-allotment option granted in connection with that offering. We refer to the December 9 and December 17, 2009 issuances collectively as the 2009 equity offering. In connection with the 2009 equity offering, we also issued 140,817 general partner units to our general partner. Net proceeds from the 2009 equity offering of approximately $122.5 million were used to repay amounts outstanding under our revolving credit facility and to partially fund the Granger acquisition in January 2010.

Initial public offering. In May 2008, we closed our initial public offering of 18,750,000 common units at a price of $16.50 per unit. In June 2008, we issued an additional 2,060,875 common units to the public pursuant to the partial exercise of the underwriters over-allotment option granted in connection with our initial public offering. The May and June 2008 issuances are referred to collectively as the initial public offering.

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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 within the midstream energy industry 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. We actively seek to provide services under long-term fee-based agreements, and approximately two-thirds of our midstream services are provided under such arrangements. In addition, we entered into fixed-price swap agreements with Anadarko to manage commodity price risk otherwise associated with our percent-of-proceeds and keep-whole contracts.

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, as the indirect owner of our general partner interest, all of the IDRs and, as of December 31, 2010, a 46.5% limited partner interest in us, is motivated to promote and support the successful execution of our business plan and to pursue projects that enhance the value of our business.

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 which 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. During 2010, we acquired the Granger assets, Wattenberg assets and White Cliffs investment with a combination of borrowings under our revolving credit facility, a $250.0 million Wattenberg term loan provided by a group of banks and operating cash flows. During 2010, we raised $345.8 million of net proceeds through equity offerings, which we used to pay amounts outstanding under our revolving credit facility. As of December 31, 2010, we had $401.0 million of borrowing capacity available to us under our revolving credit facility, and expect to have approximately $100.0 million of borrowing capacity under our revolving credit facility after the closing of the Platte Valley acquisition described under the caption *Items Affecting the Comparability of Our Financial Results* within *Item 7* of this annual report. 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.

Substantial presence in liquids-rich basins. Our asset portfolio includes gathering and processing systems in areas in which the natural gas contains a significant content of NGLs, for which pricing is correlated to the price of crude oil as opposed to natural gas. Due to the relatively high current price of crude oil, 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 dry gas areas, offering expansion opportunities for certain of our systems as producers attempt to increase their NGL production. For example, Anadarko has indicated it redirected its capital investment plans in 2010 and 2011 to target development in areas that offer higher liquids yields, or liquids-rich areas.

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Mature asset portfolio. Our asset portfolio currently has relatively low capital expenditure requirements. Total capital expenditures for the years ended December 31, 2010 and 2009 were $76.8 million and $74.6 million, respectively, including approximately $40.6 million and $24.7 million, respectively, of capital expenditures prior to our acquisition of the Partnership Assets. For the years ended December 31, 2010 and 2009, our expansion capital expenditures, including 51% of Chipeta s expenditures, were $53.1 million and $31.1 million, respectively, and our maintenance capital expenditures were $22.3 million and $23.9 million, respectively.

Well-positioned, well-maintained and efficient assets. We believe that our asset portfolio across diverse areas of operation provide 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 which 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 annual report.

OUR RELATIONSHIP WITH ANADARKO PETROLEUM CORPORATION

One of our principal strengths is our relationship with Anadarko. Our operations and activities are managed by our general partner, which is a wholly owned subsidiary of Anadarko. 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 expect to utilize the significant experience of Anadarko s management team to execute our growth strategy, which includes acquiring and constructing additional midstream assets.

As of December 31, 2010, Anadarko indirectly held 1,583,128 general partner units representing a 2.0% general partner interest in the Partnership, 100% of the Partnership IDRs through its ownership of our general partner, and 10,302,631 common units and 26,536,306 subordinated units, which comprise an aggregate 46.5% limited partner interest in the Partnership. The public held 40,734,337 common units, representing a 51.5% limited partner 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 of limited and general partner interests in us, 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 annual report 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. In connection with our gathering services, we retain and sell drip condensate, which falls out of the natural gas stream during gathering.

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

Treating and dehydration. To the extent that gathered natural gas contains contaminants, such as water vapor, 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.

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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 and the revenues are based on the price of NGLs.

There are two forms of contracts utilized in the transportation of natural gas, NGLs and crude oil, as described below:

Firm. Firm transportation service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported.

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

See *Note 2 Summary of Significant Accounting Policies* of the notes to the consolidated financial statements included under *Item 8* of this annual report for information regarding our contracts.

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PROPERTIES

As of December 31, 2010, our assets consist of ten gathering systems, six natural gas treating facilities, six natural gas processing facilities, one NGL pipeline, one interstate pipeline, and noncontrolling interests in a gas gathering system and a crude oil pipeline. The following sections describe in more detail the services provided by our assets in our areas of operation. All volumes stated below are based on a standard pressure base of 14.73 pounds per square inch, absolute.

The following map depicts our significant midstream assets as of December 31, 2010.

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Rocky Mountains

Wattenberg gathering system and processing plant. The Wattenberg gathering system is a 1,760-mile wet gas gathering system in the Denver-Julesburg Basin, north and east of Denver, Colorado, and includes seven compressor stations and 64,914 of operating horsepower. The Wattenberg processing plant has two trains with combined processing capacity of 139 MMcf/d.

Customers. Anadarko-operated production represents approximately 63% of system throughput during the year ended December 31, 2010. Approximately 31% of Wattenberg system throughput was from two third-party producers and the remaining throughput was from various third-party customers.

Supply. There are 1,999 receipt points connected to the gathering system as of December 31, 2010. 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 684,000 acres in the Wattenberg field. The system is connected to over 4,500 wells. Anadarko drilled 371 wells and completed 1,777 fracs in connection with its active recompletion and re-frac program at the Wattenberg field during 2010 and has identified a five-year inventory of 4,000 to 5,000 opportunities to increase production including well locations, re-fracs and recompletions.

Delivery points. The Wattenberg gathering system has five delivery points. Primary delivery connections include BP Petroleum s Wattenberg processing plant, the Encana Oil & Gas (USA) Inc s, Platte Valley plant (formerly referred to as Encana s Fort Lupton plant) and our Fort Lupton processing plant. The two remaining delivery points are to DCP Midstream Partners, LP 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 have truck loading facilities for access to local NGL markets. BP s Wattenberg and Encana s Platte Valley processing plants also have NGL connections to the Weld Pipeline owned and operated by DCP (formerly the Buckeye Pipeline). We have entered into an agreement to purchase Encana s Platte Valley plant in the first quarter of 2011 as described under the caption *Items Affecting the Comparability of Our Financial Results* within *Item 7* of this annual report.

Granger gathering system and processing plant. The 815-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, 2010. 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 in which Anadarko controls approximately 557,000 acres. The Granger gas gathering system has over 690 receipt points.

Delivery points. The residue gas from the Granger system can be delivered to five major pipelines including the CIG pipeline and also has access to two more pipelines through the Rendezvous Pipeline Company, a FERC-regulated Questar affiliate. The NGLs have market access to Enterprise s Mid-America Pipeline (MAPL), which terminates at Mont Belvieu, Texas, and local markets for purity products.

Chipeta processing plant. We own a 51% membership interest in, and are the managing member of, Chipeta. Chipeta is a limited liability company owned by the Partnership (51.0%), Ute Energy Midstream Holdings LLC (25.0%) and Anadarko (24.0%). Chipeta owns a natural gas processing plant complex, which includes two processing trains: a refrigeration unit completed in November 2007 with a design capacity of 240 MMcf/d and a 250 MMcf/d capacity cryogenic unit which was completed in April 2009. The Chipeta system also includes the Natural Buttes plant, which provides up to 180 MMcf/d of incremental refrigeration processing capacity, and a 100% Partnership-owned 15-mile NGL pipeline connecting the Chipeta plant to a third-party pipeline. These assets provide processing and transportation services in the Greater Natural Buttes area in Uintah County, Utah.

Customers. Anadarko is the largest customer on the Chipeta system with approximately 94% of the system throughput for the year ended December 31, 2010. The balance of throughput on the system during 2010 was from two third-party customers.

Supply. The Chipeta system is well positioned to access Anadarko and third-party production in the area with excess available capacity and is the only cryogenic processing facility 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.

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Delivery points. The Chipeta plant delivers NGLs through our 15-mile pipeline to 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 delivers natural gas through the following pipelines:

Questar Gas Management s pipeline to the Kern River market;

CIG s pipeline to the Opal market;

CIG s pipeline at the Annabuttes interconnect point on the Uintah Basin lateral;

Wyoming Interstate Co. s Kanda lateral pipeline with either access to the Trailblazer system or delivery to the Northwest Pipeline or the Rockies Express Pipeline; or

Questar Pipeline Company s pipeline with interconnects with Kern River at the Goshen point.

Hilight gathering system and processing plant. The 1,105-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 10 compressor stations with 16,366 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. The Hilight plant has an additional 10,755 horsepower for refrigeration and residue gas compression, including one compressor station.

Customers. Gas gathered and processed through the Hilight system is purchased from numerous third-party customers, with the 9 largest producers providing approximately 71% of the system throughput during 2010.

Supply. The Hilight gathering system serves the gas gathering needs of several conventional producing fields in Johnson, Campbell, Natrona and Converse Counties. Our customers have historically and may continue to maintain throughput with workover activity and by developing new prospects. Based on publicly available information, these producers are planning drilling activity over the next three to five years in the area serviced by the system.

Delivery points. The Hilight plant delivers residue gas into MIGC s transmission line, which delivers to Glenrock, Wyoming. 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.

Customers. Anadarko is the largest firm shipper on the MIGC system, with approximately 95% of throughput for the year ended December 31, 2010, with the remaining throughput from eleven 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 10 years. Of the current certificated capacity of 175 MMcf/d, 85 MMcf/d is contracted through January 2011, 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 additionally provides firm backhaul service subject to flowing capacity. 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 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, 2010, 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.

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Delivery points. MIGC volumes can be redelivered to three interstate market pipelines and one intrastate pipeline, including the Wyoming Interstate Company s Medicine Bow lateral pipeline, the Colorado Interstate Gas pipeline, the Kinder Morgan interstate pipeline at the southern end of the Powder River Basin near Glenrock, Wyoming and Anadarko s MGTC intrastate pipeline, a Hinshaw pipeline that supplies local markets in Wyoming.

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. 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. The Helper Field covers approximately 19,000 acres as of December 31, 2010 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.

Fort Union gathering system. The Fort Union system is a 314-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 has three parallel pipelines, each approximately 106 miles in length, 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, L.L.C. is a partnership among Copano Pipelines/Rocky Mountains, LLC (37.04%), Crestone Powder River L.L.C. (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, 2010, the Fort Union system produces gas from approximately 9,700 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, 2010. Another of the Fort Union owners has a comparable working interest in a large majority of Anadarko s producing coal-bed methane wells. The two remaining Fort Union owners gather gas for delivery to Fort Union under contracts with acreage dedications from multiple producers in the heart of the Basin and from the coal-bed methane producing area near Sheridan, Wyoming.

Delivery points. The Fort Union system delivers coal-bed methane gas to the Glenrock, Wyoming Hub, which accesses interstate pipelines including Wyoming Interstate Gas Company, Kinder Morgan Interstate Gas Transportation Company and Colorado Interstate Gas Company. These interstate pipelines serve gas markets in the Rocky Mountains and Midwest regions of the U.S.

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. 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.

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, 2010. 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.

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

Newcastle gathering system and processing plant. The 176-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, has gross capacity of approximately 3 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 processed at the Newcastle system is purchased from 11 third-party customers, with the largest four producers providing approximately 90% of the system throughput during 2010. The largest producer, Black Hills Exploration, provided approximately 64% of the throughput during 2010.

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.

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 sales.

White Cliffs pipeline. The White Cliffs pipeline consists of a 526-mile crude oil pipeline which originates in Platteville, Colorado and terminates in Cushing, Oklahoma. It has an approximate capacity of 30,000 Bpd which can be expanded to 50,000 Bpd. At the point of origin, it has a 100,000 barrel storage facility and a truck loading facility with an additional 20,000 barrels of storage. The pipeline is a joint venture owned by SemCrude Pipeline L.P. (51.0%), Plains Pipeline L.P. (34.0%), Noble Energy, Inc. (5.0%) and the Partnership (10.0%).

Customers. Approximately 54% and 38% of the White Cliffs pipeline throughput was from Anadarko and Noble Energy, respectively, for the year ended December 31, 2010.

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

Delivery points. The White Cliffs pipeline delivery point is SemCrude s storage facility in Cushing, Oklahoma, a major crude oil marketing center, which ultimately delivers to 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 45 compressor stations with a combined 91,105 horsepower of compression.

Customers. Anadarko is the largest customer on the Hugoton gathering system with approximately 71% of the system throughput during the year ended December 31, 2010. Approximately 24% of the throughput on the Hugoton system for the year ended December 31, 2010 was from one third-party shipper with the balance consisting of 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 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 new wells the third-party producer may successfully drill.

Delivery points. The Hugoton gathering system is connected to DCP Midstream Partners, LP s National Helium plant, which extracts NGLs and helium and redelivers residue gas into the Panhandle Eastern pipeline. The system is also connected to Pioneer Natural Resources Corporation s Satanta plant for NGLs processing and to the adjacent Mid-Continent Market Center, which provides access to the Panhandle Eastern pipeline, the Northern Natural Gas pipeline, the Natural Gas pipeline, the Southern Star pipeline, and the ANR pipeline. These pipelines provide transportation and market access to Midwestern and Northeastern markets. Anadarko acquired a 49% interest in the Satanta plant in January 2011.

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East Texas

Dew gathering system. The 323-mile Dew gathering system is located in Anderson, Freestone, Leon and Robertson Counties of East Texas. The Dew gathering system provides gathering services for Anadarko s drilling program in the Bossier play. 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 36,535 horsepower of compression.

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

Supply. As of December 31, 2010, Anadarko has approximately 836 producing wells in the Bossier play and controls approximately 139,000 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.

Pinnacle gathering system. The Pinnacle gathering system includes our 265-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 89% of system throughput for the year ended December 31, 2010. Approximately 9% of throughput on the system during 2010 was primarily from two 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. During 2008, in response to dedicated demand from a third party, we expanded the Bethel treating facilities by installing an additional 11 LTD of sulfur treating capacity to bring the total installed sulfur treating capacity to 20 LTD. 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 Enterprise Texas Pipeline, LP s pipeline, the Energy Transfer Fuels pipeline, the ETC Texas pipeline, Kinder Morgan s Tejas pipeline, the ATMOS Texas pipeline and the Enbridge Pipelines (East Texas) LP 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, 2010. The remaining 31% of throughput is attributable to Anadarko s partner in the Haley area.

Supply. In the greater Delaware basin, Anadarko has access to approximately 346,000 gross acres as of December 31, 2010, 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, L.P. 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

We do not currently face significant competition on the majority of our systems due to the substantial throughput volumes being owned or controlled by Anadarko and its dedication to us of future production 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.

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. We believe the primary competitive advantages of our Wattenberg, Granger, Hilight and Newcastle systems, which gather and process affiliate and/or third-party volumes, are their proximity to established and 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. Further, we believe that Chipeta s cryogenic processing unit and Fort Union s centralized amine treating facilities provide competitive advantages to those systems.

The following table summarizes the primary competitors for our gathering systems and processing plants.

System	Competitor(s)
Chipeta processing plant	Questar Gas Management
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 and TransCanada
Granger gathering system and processing plant	Williams Field Services, Enterprise/TEPPCO and Questar Gas Management
Haley gathering system	Anadarko s Delaware Basin Joint Venture, Enterprise GC, LP and Southern Union Energy Services Company
Helper and Clawson gathering systems	Questar Gas Management
Hilight gathering and processing system	DCP Midstream and Merit Energy
Hugoton gathering system	ONEOK Gas Gathering Company, DCP Midstream Partners, LP and Pioneer Natural Resources
Newcastle gathering and processing system	DCP Midstream

Wattenberg gathering system and processing plant	DCP Midstream, BP Petroleum and Encana Natural Gas

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, the interconnected pipelines and gas quality issues. MIGC s major competitors are Thunder Creek Gas Services, TransCanada s Bison pipeline, which commenced operations in January 2011, and the Fort Union gathering system. The White Cliffs pipeline faces no direct competition from other pipelines, although shippers could sell crude oil in local markets rather than ship to Cushing, Oklahoma.

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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, or PHMSA, of the Department of Transportation, or the DOT, pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, with respect to natural gas and Hazardous Liquids Pipeline Safety Act of 1979, as amended, or the HLPSA, with respect to NGLs. Both the NGPSA and the HLPSA have been amended by the Pipeline Safety Improvement Act of 2002, or the 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. liquid and gas transportation pipelines and some gathering lines in high-population areas.

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.

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.

In addition, we are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or 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 EPA s 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 regulations, as well as the EPA s Risk Management Program, or 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. Flammable liquids stored in atmospheric tanks below their normal boiling points without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in material compliance with all applicable laws and regulations relating to worker health and safety.

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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, or the NGA. Under the NGA, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as the following:

- rates, services, and terms and conditions of service;
- 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.

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 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.

Commencing in 2003, FERC issued a series of orders adopting rules for new Standards of Conduct for Transmission Providers (Order No. 2004), which apply to interstate natural gas pipelines and certain natural gas storage companies that provide storage services in interstate commerce. Order No. 2004 became effective in 2004. Among other matters, Order No. 2004 required interstate pipeline and storage companies to operate independently from their energy affiliates, prohibited interstate pipeline and storage companies from providing non-public transportation or shipper information to their energy affiliates, prohibited interstate pipeline and storage companies from favoring their energy affiliates in providing service, and obligated interstate pipeline and storage companies to post on their websites a number of items of information concerning the company, including its organizational structure, facilities shared with energy affiliates, discounts given for services and instances in which the company has agreed to waive discretionary terms of its tariff. On July 7, 2004, FERC issued an order providing MIGC with a partial waiver of the independent functioning and information access provisions of the standards of conduct.

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Late in 2006, the D.C. Circuit vacated and remanded Order No. 2004 as it relates to natural gas transportation providers, including MIGC. The D.C. Circuit found that FERC had not adequately justified its expansion of the prior standards of conduct to include energy affiliates, and vacated the entire rule as it relates to natural gas transportation providers. On January 9, 2007, as clarified on March 21, 2007, FERC issued an interim rule (Order No. 690) re-promulgating on an interim basis the standards of conduct that were not challenged before the court, while FERC decided how to respond to the court s decision on a permanent basis through FERC s rulemaking process. On October 16, 2008, FERC issued Order No. 717, a final rule that amends the regulations adopted on an interim basis in Order No. 690. 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. A number of parties have requested clarification or rehearing of Order No. 717, and FERC issued an order on rehearing on October 15, 2009. The order on rehearing generally reaffirmed the determinations in Order No. 717 and also clarified certain provisions of the Standards of Conduct.

Order No. 717-B, Order on Rehearing and Clarification was issued on November 16, 2009, but does not substantively affect the above discussion.

Order No. 717-C, Order on Rehearing and Clarification was issued on April 16, 2010. This Order clarifies the Commission s approach to determining whether certain employees execute transmission or marketing functions within an organization and clarifies certain exemptions to the no conduit rule, but does not substantively affect the above discussion.

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 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 December 8, 2006, FERC issued another order addressing the income tax allowance in rates. In the December 8, 2006 order, FERC refined and reaffirmed prior statements regarding its income tax allowance policy, and notably raised a new issue regarding the implication of the policy statement for publicly traded partnerships. It noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a tax savings. FERC stated that it is concerned that this created an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline s equity rate of return downward based on the percentage by which the publicly traded partnership s cash flow exceeded taxable income. On February 7, 2007, the pipeline filed a request for rehearing on this issue. FERC issued an order on rehearing of the December 8, 2006 order on May 2, 2008, establishing a paper hearing on certain issues and determining that the remaining issues not addressed in the paper hearing would be addressed in an order following the completion of the paper hearing. Rehearing of the May 2, 2008 order has been granted and is currently pending. A partial offer of settlement of the issues subject to the paper hearing has been filed, and FERC action on the partial settlement is currently pending. The ultimate outcome of this proceeding cannot be predicted with certainty.

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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, or DCF, model. In the policy statement, which modified a proposed policy statement issued in July 2007, FERC concluded (1) 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, or the 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. 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, or 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. In June 2010, FERC issued an Order granting clarification regarding Order No. 704, and, in order to provide respondents time to implement new regulations related to Order No. 704, the FERC extended the deadline for calendar year 2009 until October 1, 2010. The due date of the report for calendar year 2010 and subsequent years remains May 1 of the following calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. 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. 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. Numerous parties requested modification or reconsideration of this rule. A staff technical conference was held in March 2009 to gather additional information on three issues raised in the requests for rehearing: (1) the definition of major non-interstate pipelines, (2) what constitutes scheduling for a receipt or delivery point and (3) how a 15,000 MMBtu per day design capacity threshold would be applied. Furthermore, FERC issued an order on July 16, 2009, requesting parties to file supplemental comments on certain issues.

An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Major non-interstate pipelines subject to the rule have 150 days to comply with the rule s Internet posting requirements. On July 21, 2010, the FERC issued Order No. 720-B, which further clarified Order Nos. 720 and 720-A, but did not substantively alter the Orders 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. 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 also extends the Commission s periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 becomes effective on April 1, 2011. On December 16, 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and Hinshaw pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Order No. 735-A did grant rehearing of three requests, including removing the requirement that the quarterly reports include the contract end-date for interruptible transactions, eliminating the increased per-customer revenue reporting requirements, and extending the deadline for submitting the quarterly reports from 30 days to 60 days following the quarter-end date. The Commission issued a Notice of Inquiry simultaneously with Order No. 735-A to consider issues related to existing semiannual storage reporting requirements for both interstate pipelines and section 311 and Hinshaw pipelines. One of the issues the Notice of Inquiry addresses is whether a change is warranted in the current per-customer storage revenue reporting requirement, including the confidentiality of that information.

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, or 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.

Gathering pipeline regulation. Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. However, some of our natural gas gathering activity is subject to Internet posting requirements imposed by FERC as a result of FERC s market transparency initiatives. 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 H.B. 3273, or the Competition Bill, and H.B. 1920, or the LUG Bill. The Texas Competition Bill and LUG Bill contain provisions applicable to gathering facilities. The Competition Bill allows the Railroad Commission of Texas, or the 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. Congress from time to time has considered legislation on pipeline safety and the U.S. Department of Transportation has announced a review of its safety rules and its intention to strengthen those rules. While we cannot predict the outcome of these legislative and regulatory initiatives, legislative and regulatory changes could have a material effect on our operations and could subject us to more comprehensive and stringent safety regulation and greater penalties for violations of safety rules.

Health care reform. In March 2010, the Patient Protection and Affordable Care Act, or PPACA, and the Health Care and Education Reconciliation Act of 2010, or HCERA, which makes various amendments to certain aspects of the PPACA, were signed into law. The HCERA, together with PPACA, are referred to as the Acts. Among numerous other items, the Acts reduce the tax benefits available to an employer that receives the Medicare Part D tax benefit, impose excise taxes on high-cost health plans, and provide for the phase-out of the Medicare Part D coverage gap. These changes are not expected to have a material impact on our financial condition, results of operations or cash flows.

Financial reform legislation. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173) was signed into law. Among numerous other items, HR 4173 requires most derivative transactions to be centrally cleared and/or executed on an exchange, and additional capital and margin requirements will be prescribed for most non-cleared trades starting in 2011. Non-financial entities which 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 of its ability to meet its financial obligations before such exemption will be allowed. Additionally, financial institutions are required to spin off commodity, agriculture and energy swaps business into separately capitalized affiliates, which may reduce the number of available counterparties with whom the Partnership or Anadarko could contract. The Commodity Futures Trading

Commission has issued and requested comments on proposed regulations that set out the circumstances under which certain end users could elect to be exempt from the clearing requirements of HR 4173; however, the Partnership 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 operation of pipelines, plants and other facilities to provide midstream services is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as the following:

- requiring the acquisition of various permits to conduct regulated activities;
- requiring the installation of pollution-control equipment or otherwise restricting the way we can handle or dispose of our wastes;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- requiring investigatory and remedial actions to mitigate or eliminate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with such environmental laws and regulations and permits issued pursuant thereto.

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. Certain environmental statutes impose strict, and in some cases, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released; thus, we may be subject to environmental liability at our currently owned or operated facilities for conditions caused prior to our involvement.

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 different from 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. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

We do not believe that compliance with current federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial condition, results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, process, compress, treat and transport natural gas and NGLs. We can make no assurances, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of several of the material environmental laws and regulations that relate to our business. We believe that we are in material compliance with applicable environmental laws and regulations.

Hazardous substances and wastes. Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous wastes and may impose strict, and in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons referred to as potentially responsible parties, or PRPs, and including current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, PRPs 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 Environmental Protection Agency or 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 the costs they incur from the PRPs. 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.

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Despite the petroleum exclusion of CERCLA Section 101(14), which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA, or similar state statutes, 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 Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA s hazardous waste regulations. However, it is possible that these wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and, therefore, be subject to more rigorous and costly disposal requirements. Any such changes in these hazardous waste laws and regulations 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. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our financial condition, results of operations or cash flows.

Air. Our operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions 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 believe that we are in material compliance with these requirements. 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. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

Climate change. In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHG, present an endangerment to public heath and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that would require a reduction in emissions of GHG from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that 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 that have yet to be developed. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. With regards to the monitoring and reporting of GHG, on November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule published in October 2009 to include 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, and to require the reporting of GHG emissions from covered facilities on an annual basis beginning in 2012 for GHG emissions occurring in 2011.

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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.

Water. The federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants or dredged and fill material into state waters as well as waters of the U.S. and adjacent wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of permits issued by the EPA, the Army Corps of Engineers or an analogous state agency. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in material compliance with these requirements. However, 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 and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

Endangered species. The Endangered Species Act, or 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 material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Anti-terrorism measures. The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, on November 20, 2007, further issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. We have determined the extent to which our facilities are subject to the rule, made the necessary notifications and determined that the requirements will not have a material impact on our financial condition, results of operations or cash flows.

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TITLE TO PROPERTIES AND RIGHTS-OF-WAY

Our real property is classified into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We 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, 2010, Anadarko employed approximately 280 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 similar words. These statemen 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;

legislative or regulatory changes, including changes in environmental regulations; environmental risks; regulations by the Federal Energy Regulatory Commission, or FERC; and liability under federal and state laws and regulations;

changes in the financial or operational condition of our sponsor, Anadarko, including the outcome of the Deepwater Horizon events;

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;

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 annual report and in our other public filings and press releases.

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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.

Limited partner 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 annual report in evaluating an investment in our common units.

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

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RISKS 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, 2010, Anadarko owned or controlled approximately 74% of our gathering, processing and transportation volumes. 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.

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, including the ability to resume drilling operations in the Gulf of Mexico due to delays in the processing and approval of drilling permits and exploration and oil spill-response plans; and

losses from pending or future litigation.

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Further, we are subject to the risk of non-payment or non-performance by Anadarko, including with respect to our gathering and transportation agreements, our $260.0 million note receivable 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, may be adversely affected by any impairments to Anadarko s financial condition or adverse changes in its credit ratings. In June 2010, Moody s Investors Service, or Moody s, downgraded Anadarko s long-term debt rating from Baa3 to Ba1 and placed Anadarko s long-term ratings under review for further possible downgrade. Also in June 2010, Standard & Poor s, or S&P, affirmed its BBB- rating, but revised its outlook from stable to negative. At December 31, 2010, S&P and Fitch Ratings, or Fitch, continued to rate Anadarko s debt at BBB-, with a negative outlook. Moody s affirmed its Ba1 rating, but with a stable outlook at December 31, 2010.

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 annual report on Form 10-K for the year ended December 31, 2010 for a full discussion of the risks associated with Anadarko s business.

Anadarko may incur significant costs and be subject to claims and liability as a result of the Deepwater Horizon events in the Gulf of Mexico.

Anadarko is a 25% non-operating interest owner in the well associated with the April 2010 explosion of the Deepwater Horizon drilling rig and resulting crude-oil spill into the Gulf of Mexico. The Deepwater Horizon events could result in Anadarko incurring potential environmental liabilities and sanctions, losses from pending or future litigation, reduced availability or increased cost of capital to fund future exploration and development, the tightening of or lack of access to insurance coverage for offshore drilling activities and adverse governmental and environmental regulations. The adverse resolution of matters related to the Deepwater Horizon events could subject Anadarko to significant contractual costs, monetary damages, fines and other penalties, which could have a material adverse effect on Anadarko s business, prospects, results of operations, financial condition and liquidity. Material losses by Anadarko could, among other things, impact our ability to access the capital markets, or the pricing we receive therein, and could also limit our opportunities for organic growth around Anadarko s production assets. If these events were to occur, 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.

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.

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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 and subordinated units.

In order to pay the announced distribution of $0.38 per unit per quarter, or $1.52 per unit per year, we will require available cash of approximately $30.6 million per quarter, or $122.3 million per year, based on the number of general partner units and common and subordinated units outstanding at February 18, 2011. 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.

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.

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

Lower natural gas, NGL or oil prices could impact natural gas and oil exploration and production activity levels and result in a decline in the production of natural gas and condensate, resulting in reduced throughput on our systems. Any such decline 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, 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, or LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials such as in the Mid-Continent or Rocky Mountains;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of natural gas, NGLs and other commodities.

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, 2010, approximately 29% 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.

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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 generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to the borrower s current debt, and reduced, or in some cases, ceased to provide funding to borrowers. Further, we may be unable to obtain adequate funding under our revolving credit facility 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.

Restrictions in our revolving credit facility and Wattenberg term loan agreement 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 our revolving credit facility and Wattenberg term loan agreement 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. Our revolving credit facility and Wattenberg term loan agreement 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 revolving credit facility or agree to restrictions on our ability to grant additional liens to secure our obligations under our revolving credit facility;
- make certain loans or investments;
- 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 financial covenants of our revolving credit facility and Wattenberg term loan agreement include financial leverage and interest coverage ratios. The terms of these agreements require us to maintain (i) a ratio of total debt to Consolidated Earnings Before Interest, Taxes, Depreciation and Amortization, or Consolidated EBITDA, as defined in the credit agreement and Wattenberg term loan agreement, of 4.5 or less and (ii) a ratio of Consolidated EBITDA, as defined in the credit agreement and Wattenberg term loan agreement, to interest expense of 3.0 or greater. As of December 31, 2010, we were in compliance with those covenants. See *Item 7* of this annual report for a further discussion of the terms of our revolving credit facility and Wattenberg term loan.

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

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 Wattenberg term loan agreement and revolving credit facility, would increase. If interest rates rise, our future financing costs could increase accordingly. In addition, as is true with other MLPs (the common units of which are often viewed by investors as yield-oriented securities), our unit price is impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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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 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 and subordinated 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, 2010 on all of our units and the corresponding distribution on our general partner s 2.0% interest for four quarters is approximately $122.3 million.

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

We typically do not obtain independent evaluations of natural gas reserves connected to our systems. Accordingly, we do not have independent estimates of total reserves connected to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our systems are less than we anticipate 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.

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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, 2010, we had approximately $60.2 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 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 Natural Gas Act of 1938, or the NGA, and the EPAct 2005. Under the NGA, FERC has the authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Federal regulation extends to such matters as 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 all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation. FERC also has the power to order disgorgement of profits from transactions deemed to violate the NGA and EPAct 2005.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenues.

An increasing percentage of our customers oil and gas production is being developed from unconventional sources, such as deep gas shales. These reservoirs require hydraulic fracturing completion processes to release the gas from the rock so it can flow through casing to the surface. Hydraulic fracturing involves the injection of water, sand and, in some cases, chemicals under pressure into the formation to stimulate gas production. The process is typically regulated by state oil and gas commissions. However, certain environmental groups have advocated that additional laws are needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation was proposed in the recently ended session of Congress to provide for federal regulation of hydraulic fracturing as well as to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. In addition, the EPA, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized, a draft of which must be published by June 1, 2011

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followed by a 30-day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed and Wyoming has adopted legislation requiring drilling operators conducting hydraulic fracturing activities in that state to publicly disclose the chemicals used in the fracturing process. Additional levels of regulation and permits, if required through the adoption of new laws and regulations, could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of natural gas that move through our systems. Such developments could materially adversely affect our revenues, results of operations and cash available for distribution.

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

Following its determination that emissions of CO_2, methane and other greenhouse gases, or GHG, present an endangerment to public heath and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that establish motor vehicle GHG emission standards effective January 2, 2011 and also trigger, according to the agency, Prevention of Significant Deterioration, or PSD, and Title V permit requirements for 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. It is widely expected that 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 that have yet to be developed. The EPA s rules relating to emissions of GHG from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

The EPA also recently published regulations on November 30, 2010 that require 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, to monitor and report GHG emissions from covered facilities on an annual basis, beginning in 2012 for GHG emissions occurring in 2011. In addition, 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.

The recent adoption of derivatives legislation by the U.S. Congress 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 recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or HR 4173, 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. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the new legislation, the CFTC has proposed 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 would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. 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 new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing commodity price contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of commodity price contracts as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make cash distributions to our unitholders.

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. However, some of our gas gathering activities are subject to Internet posting requirements imposed by FERC as a result of FERC s market transparency initiatives. 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.

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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 Department of Transportation, or the DOT, through the Pipeline and Hazardous Materials Safety Administration, or 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;

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.

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 master limited partnerships, or MLPs, should be included in the proxy group used to determine return on equity, and made various determinations on how the FERC s Discounted Cash Flow, or 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 and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection. Examples of these laws include the following:

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

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities for pollution resulting from our operations or existing at our owned or operated facilities. Numerous governmental authorities, such as the EPA, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations.

There is an inherent risk of incurring significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbon wastes and potential emissions and discharges related to our operations. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of substances or wastes on, under or from our properties and facilities, many of which have been used for midstream activities for many years, often by third parties not under our control. Private parties, including the owners of the properties through which our gathering or transportation systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our results of operations or financial condition. Finally, future federal and/or state restrictions, caps, or taxes on GHG emissions that may be passed in response to climate change or hydraulic fracturing concerns may impose additional capital investment requirements, increase our operating costs and reduce the demand for our services.

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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.

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, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- leaks of natural gas containing hazardous quantities of hydrogen sulfide from our Pinnacle gathering system or Bethel treating facility;
- fires and explosions; and
- other hazards that could also result in personal injury, loss of life, pollution 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 environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to certain indemnification rights, for potential environmental liabilities.

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

On some of our systems, we rely on a significant number of third-party customers for substantially all of our revenues related to those assets. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts or otherwise, could reduce our ability to make cash distributions to our unitholders.

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

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

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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 partner and the ability of the subordinated units to convert to common units.

- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

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 on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights.

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.

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Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.

Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.

Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner s incentive distribution rights 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 annual report.

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

Our general partner s liability regarding our obligations is limited.

Our general partner included provisions in its and our contractual arrangements that limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner s 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.

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

We expect that we will 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 or in our revolving credit facility 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 and subordinated 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.

Our partnership agreement restricts the remedies available to holders of our common and subordinated 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 incentive distribution rights, 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 incentive distribution rights 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 incentive distribution rights 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.

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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 662/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of February 18, 2011, Anadarko owns 47.5% of our outstanding common and subordinated units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud, gross negligence or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholders dissatisfaction with our general partner s performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;

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.

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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 18, 2011, Anadarko holds an aggregate of 10,302,631 common units and 26,536,306 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. 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 18, 2011, Anadarko owns approximately 20.2% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), Anadarko will own approximately 47.5% of our outstanding common units.

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

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

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

- that 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.

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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, or the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or contract rights so as to fall outside of the definition of investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property from or to our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events would adversely affect the price of our common units and could have a material adverse effect on our business.

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

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;
- fluctuations in broader securities market prices and volumes, particularly among securities of midstream companies and securities of publicly traded limited partnerships;
- changes in market valuations of similar companies;
- departures of key personnel;
- commencement of or involvement in litigation;
- variations in our quarterly results of operations or those of midstream companies;
- variations in the amount of our quarterly cash distributions;
- future issuances and sales of our common units; and
- changes in general conditions in the U.S. economy, financial markets or the midstream industry.

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

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TAX RISKS TO COMMON UNITHOLDERS

Our 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, or the 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 could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for 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, franchise 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.

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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.

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 or 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, or 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.

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.

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 a fiscal year ending December 31, 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 annual report for more information.

Item 4. (Removed and Reserved)

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 as well as the amount of cash distributions declared and paid by quarter for the years ended December 31, 2010 and 2009.

	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
2010				
High Price	**$ 31.35**	**$ 27.17**	**$ 23.95**	**$ 23.50**
Low Price	**$ 27.12**	**$ 21.25**	**$ 19.78**	**$ 19.42**
Distribution per common and subordinated unit	**$ 0.38**	**$ 0.37**	**$ 0.35**	**$ 0.34**
2009				
High Price	$ 20.00	$ 17.99	$ 15.80	$ 16.65
Low Price	$ 17.11	$ 15.03	$ 13.22	$ 12.20
Distribution per common and subordinated unit	$ 0.33	$ 0.32	$ 0.31	$ 0.30

As of February 18, 2011, there were approximately 19 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 26,536,306 subordinated units and 1,583,128 general partner units, for which there is no established public trading market. All of the subordinated units and general partner units are held by affiliates of our general partner. Our general partner and its affiliates receive quarterly distributions on these units only after sufficient funds have been paid to the common units. See the caption *Selected Information From Our Partnership Agreement* within this *Item 5*.

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OTHER SECURITIES MATTERS

Sales of unregistered units. In connection with our May 2008 initial public offering, we issued 1,083,115 general partner units to our general partner, representing its initial 2.0% general partner interest in us, and 100% of our IDRs, which entitle our general partner to increasing percentages up to a maximum of 50.0% of cash distributions based on the amount of the quarterly cash distribution. We also issued 5,725,431 common units and 26,536,306 subordinated units to a subsidiary of Anadarko. Subsidiaries of Anadarko contributed our initial assets to us in connection with the offering. In connection with our November 2010, May 2010 and 2009 follow-on equity offerings, our general partner purchased an additional 171,734 general partner units, 93,035 general partner units and 140,817 general partner units, respectively, to maintain its 2.0% general partner interest in us. In August 2010, we acquired the Wattenberg assets from Anadarko for consideration consisting of $473.1 million in cash, 1,048,196 common units and 21,392 general partner units. In January 2010, we acquired the Granger assets from Anadarko for consideration consisting of $241.7 million cash, 620,689 common units and 12,667 general partner units. In July 2009, we acquired the Chipeta assets from Anadarko for consideration consisting of $101.5 million cash, 351,424 common units and 7,172 general partner units. Further, in December 2008, we acquired the Powder River assets from Anadarko for consideration consisting of $175.0 million cash, 2,556,891 common units and 52,181 general partner units. The common units, subordinated units and general partner units issued in connection with these transactions were issued to our general partner or other subsidiaries of Anadarko in private placements that were not registered with the SEC pursuant to an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended.

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, or LTIP, which permits the issuance of up to 2,250,000 units. 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 annual report, which is incorporated by reference into this *Item 5*.

SELECTED INFORMATION FROM OUR PARTNERSHIP AGREEMENT

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