PAA NATURAL GAS STORAGE LP
Form 424B4
May 03, 2010

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Filed Pursuant to Rule 424(b)(4)
Registration No. 333-164492

PROSPECTUS

11,720,000 Common Units
Representing Limited Partner Interests

This is the initial public offering of our common units. Prior to this offering, there has been no public market for our common units. Our common units have been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol PNG.

Investing in our common units involves risks. Please read Risk Factors beginning on page 24. These risks include the following:

- We may not have sufficient cash following the establishment of reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to holders of our common units and Series A subordinated units.

- Plains All American Pipeline, L.P., or PAA, owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including PAA, have conflicts of interest with us and limited fiduciary duties, and may favor their own interests to your detriment.

- Increased competition from other companies that provide natural gas storage services or services that can substitute for storage services could have a negative impact on the demand for our services, which could adversely affect our financial results.

- Our natural gas storage operations are subject to regulation by federal, state and local regulatory authorities; regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

- We may not be able to maintain or replace expiring storage contracts.

- We may not be able to achieve our current expansion plans at our Pine Prairie facility on economically viable terms.

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

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

- Upon the closing of the offering, investors in our common units will experience immediate and substantial dilution in pro forma net tangible book value of $10.56 per common unit.

- You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

	Price to Public	Underwriting Discounts	Proceeds to PAA Natural Gas Storage, L.P.
Per Common Unit	$ 21.50	$ 1.32	$ 20.18
Total	$ 251,980,000	$ 15,470,400	$ 236,509,600

We have granted the underwriters a 30-day option to purchase up to an additional 1,758,000 common units from us on the same terms and conditions as set forth above if the underwriters sell more than 11,720,000 common units in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units on or about May 5, 2010.

Barclays Capital **UBS Investment Bank** **Citi** **Wells Fargo Securities**

BofA Merrill Lynch **J.P. Morgan** **Raymond James**

Madison Williams
Morgan Keegan & Company, Inc.
RBC Capital Markets
Stifel Nicolaus

April 29, 2010

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SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary does not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including Risk Factors beginning on page 24 and the historical and pro forma financial statements and the notes to those financial statements. The information in this prospectus assumes, unless otherwise indicated, that the underwriters option to purchase additional common units is not exercised. We include a glossary of some of the terms used in this prospectus as Appendix B.

References in this prospectus to PAA Natural Gas Storage, L.P., the Partnership, PNGS, we, us, our or similar terms when used in a historical context refer to the business of PAA Natural Gas Storage, LLC and its subsidiaries, which will be contributed to PAA Natural Gas Storage, L.P. in connection with this offering. When used in the present tense or prospectively, those terms refer to PAA Natural Gas Storage, L.P. and its subsidiaries. References in this prospectus to our general partner refer to PNGS GP LLC. Unless the context indicates otherwise, (i) all references to Plains All American or PAA refer to Plains All American Pipeline, L.P. (the ultimate parent company of our general partner) and its subsidiaries and affiliates other than PAA Natural Gas Storage, L.P. and our general partner and their respective subsidiaries, as of the closing date of this offering, (ii) all references to volumes of storage capacity are expressed in billions of cubic feet of natural gas, or Bcf, and are approximations that have been rounded to the nearest Bcf and (iii) all references to capacity mean working gas storage capacity.

PAA Natural Gas Storage, L.P.

Overview

We are a fee-based, growth-oriented Delaware limited partnership formed by Plains All American to own, operate and grow the natural gas storage business that PAA acquired in 2005. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. We currently own and operate two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. We also lease storage capacity and pipeline transportation capacity from third parties from time to time in order to increase our operational flexibility and enhance the services we offer our customers. As of April 1, 2010, we had 5.3 Bcf of storage capacity under lease from third parties and had secured the right to 286 MMcf per day of firm transportation service on various pipelines. Substantially all of our revenues are derived from the provision of firm storage services under multi-year, fee-based contracts.

Our business has expanded rapidly since its inception in 2005, primarily through organic growth initiatives. We have grown our storage capacity from 20 Bcf as of December 31, 2005 to 40 Bcf as of December 31, 2009. Our expansion plans include an additional 31 Bcf of working gas storage capacity, 28 Bcf of which we expect to place into service by mid-2012, including 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. Our target is to increase our total capacity to 68 Bcf by mid-2012, representing a 70% increase in storage capacity from year-end 2009 levels. Through our current assets and proposed expansions, we believe we are well-positioned to benefit from the anticipated long-term growth in demand for natural gas storage capacity and services in North America.

Our Assets

We own 100% of the Pine Prairie facility, which is a recently constructed, high-deliverability salt-cavern natural gas storage complex located in Evangeline Parish, Louisiana, and 100% of the Bluewater facility, which is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in

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St. Clair County, Michigan. The following table contains certain information regarding our Pine Prairie and Bluewater storage facilities:

Facility Name and Type	Working Gas Capacity (Bcf)	Peak Injection Rate (Bcf/d)	Peak Withdrawal Rate (Bcf/d)	Compression (Horsepower)
Pine Prairie (salt-cavern)				
Existing facility	14	1.2	2.4	32,000
Planned expansion	31(1)	1.2(2)	0.8(2)	56,250(3)
Subtotal:	45	2.4	3.2	88,250
Bluewater (depleted reservoir)				
Existing facility	26	0.5	0.8	13,350
Planned expansion	2(4)			
Subtotal:	28	0.5	0.8	13,350
Total (both facilities):	73	2.9	4.0	101,600

(1) We expect to place 10 Bcf into service in the second quarter of 2010, 18 Bcf by mid-2012 and the final 3 Bcf will be added ratably through 2016.

(2) We expect to complete these expansions of peak injection and withdrawal capabilities by mid-2011.

(3) Of this aggregate expected increase in compression, 16,000 horsepower is on location with installation targeted for April 2010. With respect to the remaining compression capacity, we expect 23,000 horsepower to be in place by mid-2011 and an additional 17,250 horsepower to be in place by mid-2012.

(4) We expect to place this expansion in working gas capacity into service ratably over a 10-year period beginning in 2011 in connection with a planned liquids removal project.

Pine Prairie. As a strategically located, high-deliverability storage facility, Pine Prairie has attracted a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and liquefied natural gas (LNG) importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hubs, including:

the Henry Hub, which is the delivery point for NYMEX natural gas futures contracts and is located approximately 50 miles southeast of Pine Prairie;

the Carthage Hub in east Texas, which is located approximately 150 miles northwest of Pine Prairie; and

the Perryville Hub in north Louisiana, which is located approximately 130 miles north of Pine Prairie.

Pine Prairie s pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to other significant consumer and industrial markets.

Pine Prairie has a total current working gas storage capacity of 14 Bcf in two caverns, and planned expansions that will increase Pine Prairie s total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2016 (see table above). Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

Bluewater. Bluewater is located in the State of Michigan, which contains more underground natural gas storage capacity than any other state in the U.S. according to data from the Energy Information Administration (EIA), and primarily services seasonal storage needs throughout the Midwestern and Northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater s customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater s 30-mile, 20-inch diameter pipeline header system connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario.

As indicated in the table above, Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater s working gas capacity by 2 Bcf ratably over a 10-year period beginning in 2011 as a result of a planned liquids removal project. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. As of April 1, 2010, we had leased approximately 5.3 Bcf of additional capacity at third-party natural gas storage facilities as well as 236 MMcf per day of related pipeline transportation capacity.

Our Operations

We generate revenue almost exclusively through the provision of fee-based gas storage services to our customers. Our storage rates are regulated under Federal Energy Regulatory Commission, or FERC, rate-making policies, which currently permit our facilities to charge market-based rates for our services. For the year ended December 31, 2009, approximately 99% of our total revenue was derived from fee-based storage activities, with the remaining approximately 1% primarily attributable to the sale of liquid hydrocarbons incidentally produced in connection with the operation of our depleted reservoir storage facilities at Bluewater. Our revenues from fee-based gas storage services are derived from both firm storage services and hub services.

Firm Storage Services. Firm storage services include (i) storage services pursuant to which customers receive the assured or firm right to store gas in our facilities over a multi-year period and (ii) seasonal park and loan services pursuant to which customers receive the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis. Under our firm storage contracts, our customers are obligated to pay us fixed monthly capacity reservation fees, which are owed to us regardless of the actual storage capacity utilized. At Pine Prairie, our firm storage contracts typically have terms of 3 to 5 years, while at Bluewater terms generally range from 1 to 3 years. Under our firm storage contracts, we also typically collect a cycling fee based on the volume of natural gas nominated for injection and/or withdrawal and retain a small portion of natural gas nominated for injection as compensation for our fuel use. For the year ended December 31, 2009, approximately 92% of our total revenue was derived from firm storage services.

Hub Services. We also generate revenue from the provision of hub services at our facilities. Hub services include (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) non-seasonal park and loan services and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from our facilities. For the year ended December 31, 2009, approximately 7% of our total revenue was derived from hub services.

We believe that the high percentage of our baseline cash flow derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers stabilizes our cash flow profile and substantially mitigates the risk to us of significant negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. For additional information about our contracts, please read Business Contracts.

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Our Business Strategy

Our principal business strategy is to capitalize on the anticipated long-term growth in demand for natural gas storage services in North America and increase the amount of cash distributions we make to our unitholders over time by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services. Our plan for executing this strategy includes the following key components:

- Optimizing our existing natural gas storage facilities.
- Organically expanding our existing natural gas storage facilities.
- Pursuing strategic and accretive acquisition or development projects.
- Leasing storage capacity and transportation services from third parties to enhance operational flexibility.
- Utilizing a portion of our owned and leased storage capacity to enhance our commercial management activities.

For additional discussion of our business strategy, please read Business Our Business Strategy.

Our Financial Strategy

We have targeted a general credit profile that has the following attributes:

- a long-term debt-to-total capitalization ratio of 40% or less;
- an average long-term debt-to-Adjusted EBITDA multiple of approximately 3.5x (Adjusted EBITDA is earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring); and
- an average Adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

When considered together with what we believe to be the relatively low risk profile of our business, we believe this credit profile is consistent with an investment grade credit rating and should position us to take advantage of attractive acquisition opportunities.

In order for us to maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for expansion and acquisition projects through a combination of equity capital and cash flow in excess of distributions. In connection with this offering, we entered into a new $400 million revolving credit facility. We believe we will be able to fund up to the first $250 million of acquisitions or expansion projects primarily through borrowings under this credit facility or other sources and remain in compliance with our targeted credit profile.

We have not applied for a credit rating from any credit rating agency, nor to our knowledge has any such credit rating been assigned. If and when we seek a credit rating, our credit rating may be positively or negatively impacted by the leverage and credit rating of PAA. As of April 1, 2010, the senior unsecured ratings of PAA with Standard & Poor s

Ratings Services and Moody s Investors Service were BBB-, stable outlook, and Baa3, stable outlook, respectively.

For additional discussion of our financial strategy, please read Business Our Financial Strategy.

Our Competitive Strengths

We believe that the following competitive strengths will position us to successfully execute our principal business strategy:

Our natural gas storage assets are strategically located and operationally flexible.

Our business generates relatively stable and predictable cash flow.

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Our Pine Prairie storage facility has the ability to be significantly expanded at competitive costs and with a relatively high degree of schedule certainty.

We have the evaluation, integration and engineering skill sets in-house that are necessary to successfully pursue acquisition and expansion opportunities.

We have the financial flexibility to pursue acquisition and expansion opportunities.

Our general partner has an experienced executive management team with specialized knowledge of natural gas storage and markets and whose interests are aligned with those of our unitholders.

We believe these competitive strengths will aid our efforts to expand our presence in the natural gas storage sector.

For additional discussion of our competitive strengths, please read Business Our Competitive Strengths.

Our Relationship with Plains All American Pipeline, L.P.

We believe one of our strengths is our relationship with Plains All American Pipeline, L.P., which, based on our review of publicly available data, is the fifth largest publicly traded master limited partnership as measured by equity market capitalization, which was approximately $8.0 billion as of April 29, 2010. Plains All American s common units trade on the New York Stock Exchange, or NYSE, under the ticker symbol PAA. In addition to its participation in the natural gas storage business through our partnership, PAA is engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products.

PAA and its predecessors have been active participants in the hydrocarbon storage industry since the early 1990s. PAA has a long history of successfully expanding its energy infrastructure businesses through a combination of organic growth projects and complementary acquisitions. Since its initial public offering in 1998, PAA has grown its asset base from approximately $600 million to over $12 billion and increased the annualized distribution on its limited partner units by over 100%, from $1.80 per unit as of PAA s initial public offering to $3.74 per unit for the distribution declared to be paid in May 2010.

Our partnership will own all of the natural gas storage business and assets formerly owned by PAA and PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business. Upon completion of this offering, PAA will have a significant economic stake in us and a commensurate incentive to promote and support the successful execution of our growth plan and strategy.

We believe PAA s significant presence in the energy sector, its successful track record of growth and its significant investment in, and sponsorship and support of, us will enhance our ability to grow our business. While we believe this relationship with PAA is a significant positive attribute, it may also be a source of conflicts. For example, PAA is not restricted in its ability to compete with us. Please read Conflicts of Interest and Fiduciary Duties.

Expansion Activity and First Quarter 2010 Performance Update

During the first four months of 2010, expansion activities continued at Pine Prairie. Such activities included the completion of the solution mining process on our third cavern well, which added total working capacity of 9.8 Bcf, and a fill/dewater cycle on an existing cavern well that added 0.4 Bcf of incremental working capacity. The incremental capacity associated with the completed fill/dewater cycle was placed in service late in the first quarter and the remaining 9.8 Bcf is expected to be placed in service in the second quarter of 2010, following completion of repairs to a wellhead seal that failed during initial start-up operations. Additionally, drilling operations were completed and solution mining operations commenced on our fourth cavern well, which is expected to add approximately 8 Bcf of incremental working capacity in mid-2011.

Drilling operations also commenced on our fifth cavern well, which is expected to add approximately 10 Bcf of incremental working capacity in mid-2012.

At Bluewater, drilling operations commenced on a new well in connection with our liquids removal project, intended to expand our storage capacity by 2 Bcf ratably over a ten-year period beginning in 2011.

During the first four months of 2010, at Pine Prairie we executed multi-year firm storage contracts with customers for 3.0 Bcf of working capacity, increasing to approximately 97% the total percentage of our working gas capacity at Pine Prairie committed under multi-year firm storage contracts, including the 9.8 Bcf of incremental capacity referred to above. At Bluewater, we leased an additional 2 Bcf of storage capacity at a nearby third-party facility, which we intend to use to enhance the services we provide to our customers. Except for such recently leased storage capacity, substantially all of our owned and leased capacity at Bluewater has been committed under firm storage contracts for the 2010-2011 winter storage season.

Although we are in the early stages of compiling our financial results for the first quarter of 2010, our preliminary estimated results indicate Adjusted EBITDA for the quarter will approximate the run rate experienced during the successor period of 2009. This preliminary estimate includes the negative impact of acquisition-related expenses and general and administrative expenses associated with this offering totaling approximately $1.4 million in the aggregate. These estimated results do not include any earnings associated with the expected approximate 70% increase in working gas capacity at Pine Prairie that will result from the 9.8 Bcf of additional capacity referred to above. Our current estimated range of Adjusted EBITDA for the first quarter is based on preliminary estimated results and, accordingly, remains subject to change as we complete our financial reporting procedures. These changes could be significant.

Risk Factors

An investment in our common units involves risks. The following list of risk factors is not exhaustive. Please read Risk Factors carefully for a more thorough description of these and other risks.

Risks Related to Our Business

We may not have sufficient cash following the establishment of reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to holders of our common units and Series A subordinated units.

On a pro forma basis, we would not have had sufficient available cash from distributable cash flow to pay the full minimum quarterly distribution on our common units or any distributions on our Series A subordinated units for the year ended December 31, 2009.

The amount of cash we have available for distribution to holders of our common units and Series A subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The assumptions underlying our minimum estimated available cash from distributable cash flow included in Our Cash Distribution Policy and Restrictions on Distributions involve inherent and significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated.

Increased competition from other companies that provide natural gas storage services or services that can substitute for storage services could have a negative impact on the demand for our services, which could adversely affect our financial results.

Our natural gas storage operations are subject to regulation by federal, state and local regulatory authorities; regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We may not be able to maintain or replace expiring storage contracts.

We may not be able to achieve our current expansion plans at our Pine Prairie facility on economically viable terms.

Risks Inherent in an Investment in Us

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

Cost reimbursements due to PAA s general partner 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 you. The amount and timing of such reimbursements will be determined by PAA s general partner.

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

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

Upon the closing of the offering, investors in our common units will experience immediate and substantial dilution in pro forma net tangible book value of $10.56 per common unit.

Risks Related to Conflicts of Interest

PAA owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. PAA and our general partner have conflicts of interest and may favor PAA s interests to your detriment.

PAA may engage in competition with us.

Our partnership agreement defines and modifies the duties of our general partner and restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner.

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 additional entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you could be substantially reduced.

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

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

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Formation Transactions and Partnership Structure

In connection with this offering, the following transactions, which we refer to as the formation transactions, will occur:

PAA will contribute to us 98.0% of the equity interests in the entities that own its gas storage business, in exchange for 19,864,529 common units[(1)], 13,934,351 Series A subordinated units, and 11,500,000 Series B subordinated units, representing an aggregate approximate 77.9% limited partner interest in us;

PNGS GP LLC, our general partner and a subsidiary of PAA, will contribute to us 2.0% of the equity interests in the entities that own PAA s gas storage business, in exchange for a 2.0% general partner interest in us as well as all of our incentive distribution rights, which will entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3375 per quarter;

we will issue 11,720,000 common units to the public, representing an approximate 20.1% limited partner interest in us;

we will receive, after deducting underwriting discounts and commissions and offering expenses, net proceeds of approximately $233.9 million from the issuance and sale of 11,720,000 common units at an initial offering price of $21.50 per common unit; we will use these net proceeds, together with $200 million of borrowings under our new $400 million credit facility, to repay intercompany indebtedness owed to PAA as described in Use of Proceeds; we expect that any intercompany indebtedness not repaid in connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us; and

we will also enter into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we will agree upon certain aspects of our relationship with them, including the provision by PAA s general partner to us of certain general and administrative services and employees, our agreement to reimburse PAA s general partner for the cost of such services and employees, certain indemnification obligations, the use by us of the name PAA and related marks, and other matters. Please read Certain Relationships and Related Transactions Agreements Governing the Transactions Omnibus Agreement.

(1) Of this amount, 18,106,529 common units will be issued to PAA at the closing of this offering and up to 1,758,000 common units will be issued to PAA within 30 days of this offering. However, if the underwriters exercise their option to purchase up to 1,758,000 additional common units within 30 days of this offering, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public instead of PAA. The net proceeds from any exercise of the underwriters option to purchase additional common units will be used to reimburse PAA for capital expenditures it incurred with respect to the assets contributed to us.

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Ownership of PAA Natural Gas Storage, L.P.

The diagram below illustrates our organization and ownership based on total units outstanding after giving effect to the offering and the related formation transactions and assumes that the underwriters option to purchase additional common units is not exercised.

Public Common Units	20.1%
Common Units owned by PAA	34.2%
Series A Subordinated Units owned by PAA	23.9%
Series B Subordinated Units owned by PAA	19.8%[(1)]
General Partner Interest	2.0%
Total	100.0%

(1) The Series B subordinated units will not be entitled to participate in our quarterly distributions unless and until they convert into Series A subordinated units or common units. The Series B subordinated units are, however, entitled to vote on matters submitted to a vote to our unitholders.

Management of PAA Natural Gas Storage, L.P.

PNGS GP LLC, our general partner, has sole responsibility for conducting our business and for managing our operations. The board of directors and officers of our general partner will make decisions on our behalf. PAA is the sole member of our general partner and will have the right to elect all seven members to the board of directors of our general partner, with at least three of these directors meeting the independence standards established by the New York Stock Exchange. One of such independent directors was appointed prior to the effectiveness of our registration statement and a second independent director will be appointed after the time our common units become listed for trading on the NYSE. In addition, some of the executive officers and directors of PAA also serve as executive officers and directors of our general partner. For more information about the directors and executive officers of our general partner, please read Management Directors and Executive Officers of Our General Partner.

Pursuant to our partnership agreement as well as the omnibus agreement that we will enter into concurrently with the closing of this offering, PAA and our general partner will be entitled to reimbursement for all direct and indirect expenses that they incur on our behalf. In addition, PAA and our general partner will have substantial discretion in incurring third-party expenses on our behalf. Please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Omnibus Agreement.

As is common with publicly traded partnerships and in order to maximize operational flexibility, we will conduct our operations through subsidiaries.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 333 Clay St., Suite 1500, Houston, Texas 77002, and our telephone number is (713) 646-4100. Our website will be located at www.pnglp.com and will be activated in connection with the closing of this offering. We expect to make available our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

Summary of Conflicts of Interest and Fiduciary Duties

General. Our general partner has a legal duty to manage us in a manner beneficial to holders of our common and subordinated units. This legal duty originates in statutes and judicial decisions and is commonly referred to as a fiduciary duty. However, the officers and directors of our general partner also have fiduciary duties to manage our general partner in a manner beneficial to its owner, PAA. Certain of the officers and directors of our general partner are also officers of PAA. As a result, conflicts of interest will arise in the future between us and holders of our common and subordinated units, on the one hand, and PAA and our general partner, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of cash distributions we make to the holders of common units and Series A subordinated units, which in turn has an effect on whether our general partner receives incentive cash distributions. In addition, our general partner has the discretion to take actions which may hasten the conversion of Series B subordinated units into Series A subordinated units or common units or Series A subordinated units into common units.

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Partnership Agreement Modifications to Fiduciary Duties. Our partnership agreement limits the liability of, and defines the duties owed by, our general partner to holders of our common and subordinated units. Our partnership agreement also restricts the remedies available to holders of our common and subordinated units for actions that might otherwise be challenged under state law standards as a breach of our general partner s fiduciary duties. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties under applicable state law.

PAA May Engage in Competition With Us. While PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business, PAA and its affiliates are not limited in their ability to compete with us.

For a more detailed description of the conflicts of interest and the fiduciary duties of our general partner, please read Conflicts of Interest and Fiduciary Duties.

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The Offering

Common units offered to the public	11,720,000 common units. 13,478,000 common units if the underwriters fully exercise their option to purchase additional common units.
Units outstanding after this offering	31,584,529 common units,[1] 13,934,351 Series A subordinated units and 11,500,000 Series B subordinated units for a total of 57,018,880 limited partner units. The Series B subordinated units will not be entitled to participate in our quarterly distributions, but will convert into Series A subordinated units on a one-for-one basis upon the satisfaction of certain operational and financial conditions, which include achievement of expansion activities and increases in our distribution level. If at the time the operational and financial conditions are satisfied, the subordination period has already ended, the Series B subordinated units will instead convert directly into common units on a one-for-one basis. In addition, our general partner will own a 2.0% general partner interest in us. For additional information regarding our Series B subordinated units, please read Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period Series B Subordinated Units.
Use of proceeds	We intend to use the net proceeds of approximately $236.5 million, after deducting underwriting discounts, but before paying offering expenses, together with borrowings under our credit facility, to repay intercompany indebtedness owed to PAA in the amount of approximately $433.9 million. We expect that any intercompany indebtedness not repaid in connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us. If the underwriters option to purchase additional common units is exercised, we will use the net proceeds to reimburse PAA for capital expenditures it incurred with respect to the assets contributed to us. Please read Use of Proceeds.

(1) Excludes common units subject to issuance under our Long Term Incentive Plan. Please read Management Our Long Term Incentive Plan.

Cash distributions

Upon completion of this offering, our general partner will establish a minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit ($1.35 per common unit and Series A subordinated unit on an annualized basis) to the extent we have sufficient cash after establishment of reserves and payment of fees and expenses, including payments to our general partner and its affiliates. We refer to this cash as available cash, and it is defined in our partnership agreement included in this prospectus as Appendix A and in the glossary included in this prospectus as Appendix B. Our ability to pay the minimum quarterly distribution is subject to various restrictions and other factors described in more detail under the caption Our Cash Distribution Policy and Restrictions On Distributions. We will adjust the minimum quarterly distribution payable for the period from the completion of this offering through June 30, 2010, based on the actual length of that period.

Our partnership agreement requires that we distribute all of our available cash each quarter in the following manner:

first, 98.0% to the holders of common units and 2.0% to our general partner, until each common unit has received the minimum quarterly distribution of $0.3375, plus any arrearages from prior quarters; and

second, 98.0% to the holders of Series A subordinated units and 2.0% to our general partner, until each Series A subordinated unit has received the minimum quarterly distribution of $0.3375.

If cash distributions to our unitholders exceed $0.3375 per common unit and Series A subordinated unit in any quarter, our general partner will receive, in addition to distributions on its 2.0% general partner interest, increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount. We refer to these distributions as incentive distributions. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions.

The amount of pro forma available cash from distributable cash flow generated during the year ended December 31, 2009 would have been sufficient to allow us to pay only approximately 82.6% of the minimum quarterly distribution ($0.3375 per unit per quarter, or $1.35 on an annualized basis) on our common units for such period and would not have been sufficient to pay any distributions on our Series A subordinated units for such period. Please read Our Cash Distribution Policy and Restrictions on Distributions.

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We believe that, based on the Statement of Minimum Estimated Available Cash from Distributable Cash Flow included under the caption Our Cash Distribution Policy and Restrictions on Distributions, we will have sufficient distributable cash flow to pay the minimum quarterly distribution of $0.3375 per unit on all common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest for the four quarters ending June 30, 2011. This should be read in conjunction with Risk Factors and Our Cash Distribution Policy and Restrictions on Distributions.

Series A subordinated units

PAA will initially own all of our Series A subordinated units. The principal difference between our common units and Series A subordinated units is that in any quarter during the subordination period, holders of the Series A subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Series A subordinated units will not accrue arrearages.

Conversion of Series A subordinated units

At any time on or after June 30, 2013, the subordination period will end on the first business day following the quarter in respect of which we have, for each of three consecutive, non-overlapping four quarter periods (i) generated from distributable cash flow at least $1.35 (the minimum quarterly distribution on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distribution on our general partner s 2.0% interest and (ii) paid from available cash at least $1.35 on all outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner s 2.0% interest. Additionally, at any time on or after June 30, 2011, if we have, for a period of four consecutive quarters (i) generated from distributable cash flow at least $0.5063 per quarter (150% of the minimum quarterly distribution, which is approximately $2.03 on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights and (ii) paid from available cash at least $0.5063 per quarter (150% of the minimum quarterly distribution, which is approximately $2.03 on an annualized basis) on all outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner s 2.0% interest and the related distributions on the incentive distribution rights, the subordination period will end.

Distributable cash flow will be determined by our general partner and is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received.

In addition, the subordination period will end upon the removal of our general partner other than for cause if the units held by our general partner and its affiliates are not voted in favor of such removal.

When the subordination period ends, all Series A subordinated units will convert into common units on a one-for-one basis, and all common units thereafter will no longer be entitled to arrearages.

Series B subordinated units

PAA will initially own all of the Series B subordinated units. The Series B subordinated units will not be entitled to participate in our quarterly distributions until they convert into Series A subordinated units or common units.

The Series B subordinated units are designed to compensate PAA for prior capital expenditures made by it to expand the working gas storage capacity at Pine Prairie and the future financial contribution expected to result from such investment. As of the closing of this offering, we expect to have approximately 24 Bcf of aggregate working gas storage capacity at Pine Prairie, including approximately

10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010.

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Conversion of Series B subordinated units

The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

4,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) we make a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights;

3,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) we make a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

3,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) we make a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights.

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Our general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

For additional information regarding our Series B subordinated units, please read Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period Series B Subordinated Units.

General partner s right to reset the target distribution levels

Our general partner has the right, at any time when there are no Series A subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash 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 each target distribution level will be reset to the correspondingly higher amount that causes such reset target distribution level to exceed the reset minimum quarterly distribution by the same percentage that such distribution level exceeds the then-current minimum quarterly distribution.

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	If our general partner elects to reset the target distribution levels, it will be entitled to receive common units and a general partner interest necessary to maintain its general partner interest in us immediately prior to the reset election. The number of common units to be issued to our general partner will equal the 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. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner s Right to Reset Incentive Distribution Levels.
Issuance of additional units	We have the ability to issue an unlimited number of units without the consent of our unitholders. Please read Units Eligible for Future Sale and The Partnership Agreement Issuance of Additional Securities.
Limited voting rights	Our general partner will manage and operate us. Unlike the holders of common stock in a corporation, you will have only limited voting rights on matters affecting our business. You will have no right to elect our general partner or its directors on an annual or continuing basis. Our general partner may not be removed except by a vote of the holders of at least 662/3% of the outstanding units, voting together as a single class, including any units owned by our general partner and its affiliates, including PAA. Upon consummation of this offering, PAA will own an aggregate of approximately 79.4% of our outstanding limited partner units. This will give PAA the ability to prevent the involuntary removal of our general partner. Please read The Partnership Agreement Voting Rights.
Limited call right	If at any time our general partner and its affiliates own more than 80.0% of the outstanding common units, our general partner has the right, but not the obligation, to purchase all of the remaining common units at a price that is not less than the then-current market price of the common units.
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, 2012, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be 20% or less of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.35 per unit, we estimate that your average allocable federal taxable income per year will be no more than $0.27 per unit. Please read Material Income Tax Consequences Tax Consequences of Unit Ownership Ratio of Taxable Income to Distributions.
Material income tax consequences	

	For a discussion of other material federal income tax consequences that may be relevant to prospective unitholders who are individual citizens or residents of the United States, please read Material Income Tax Consequences.
Exchange listing	Our common units have been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol PNG.

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Summary Historical and Pro Forma Financial and Operating Data

The summary historical financial and operating data below was derived from our audited consolidated balance sheets as of December 31, 2009 and 2008 and the audited consolidated statements of operations, changes in members capital and cash flows for the periods of September 3, 2009 to December 31, 2009, January 1, 2009 to September 2, 2009, and the years ended December 31, 2008 and 2007 included elsewhere in this prospectus. The summary historical financial and operating data below for the year ended December 31, 2007 and 2006 was derived from our audited consolidated balance sheets as of December 31, 2007 and 2006 and the consolidated statements of operations, changes in members capital and cash flows for the year ended December 31, 2006 not included in this prospectus.

On September 3, 2009, PAA became our sole owner by acquiring Vulcan Capital s 50% interest in us (the PAA Ownership Transaction) in exchange for $220 million, including contingent cash consideration of $40 million. At the time of the transaction, the entity had approximately $450 million of outstanding project finance debt. Although we continued as the same legal entity after the transaction, pursuant to applicable accounting principles, all of our assets and liabilities were adjusted to fair value as a result of this transaction. This change in value resulted in a new cost basis for accounting (fair value push down accounting). Accordingly, the selected financial and operating data presented below are presented for two periods, Predecessor and Successor, which relate to the accounting periods preceding and succeeding the PAA Ownership Transaction. The Predecessor and Successor periods have been separated by a vertical line to highlight the fact that the financial and operating information for such periods was prepared under two different cost bases of accounting.

The summary pro forma statement of operations data for the year ended December 31, 2009 and the summary pro forma balance sheet data as of December 31, 2009 are derived from our unaudited pro forma condensed combined financial statements included elsewhere in this prospectus. The pro forma adjustments have been prepared as if the PAA Ownership Transaction, this offering and the anticipated borrowings under our credit facility had taken place on December 31, 2009 in the case of the pro forma balance sheet, and on January 1, 2009 in the case of the pro forma statement of operations data. A more complete explanation of the pro forma data can be found in our unaudited pro forma condensed combined financial statements.

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The summary historical financial and operating data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Predecessor				Successor	Pro Forma
	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1, 2009 through September 2, 2009	September 3, 2009 through December 31, 2009	Year Ended December 31, 2009
	($ in thousands except for /Mcf numbers)					
Statement of operations data:						
Total revenues	$ 30,831	$ 36,945	$ 49,177	$ 46,929	$ 25,251	$ 72,180
Storage related costs	100	3,847	8,934	8,792	7,003	15,795
Operating costs (except those shown below)	3,658	3,947	4,059	4,820	3,257	8,077
Fuel expense	613	1,140	2,320	1,816	578	2,394
General and administrative expenses	3,402	3,755	3,874	3,562	4,083	8,897
Depreciation, depletion and amortization	3,986	4,520	6,245	8,054	3,578	12,242
Total costs and expenses	11,759	17,209	25,432	27,044	18,499	47,405
Operating income	19,072	19,736	23,745	19,885	6,752	24,775
Interest expense	(8,389)	(7,108)	(4,941)	(4,352)	(4,262)	(759)
Interest income and other income (expense), net	2,030	5,378	1,669	458	(2)	456
Income tax expense			(887)	(473)		(473)
Net income	$ 12,713	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 23,999
Balance sheet data (at end of period):						
Total assets	$ 518,092	$ 674,765	$ 811,436		$ 900,407	$ 900,407
Long-term debt(1)	227,300	352,713	415,263		450,523	200,000
Total debt(1)	227,300	355,163	417,713		450,523	200,000
Members /partners capital	264,109	294,717	363,229		432,744	683,267
Other financial data:						
Adjusted EBITDA(2)	$ 27,395	$ 29,663	$ 31,001	$ 28,701	$ 12,165(3)	$ 39,614
Distributable cash flow(2)	$ 19,006	$ 22,156	$ 25,577	$ 23,965	$ 7,200	$ 37,768
Maintenance capital expenditures	$	$	$ 377	$ 384	$ 320	$ 704

Net cash provided by (used in) operating activities	$ 13,973	$ 22,343	$ 21,818	$ 22,603	$ 15,265	
Net cash provided by (used in) investing activities	$ (206,612)	$ (177,280)	$ (118,890)	$ (58,561)	$ (9,656)	
Net cash provided by (used in) financing activities	$ 158,771	$ 145,743	$ 122,344	$ 23,636	$ (22,813)	
Operating data:						
Average monthly working capacity (Bcf)[4][5]	24	26	28	40	43	41
Average monthly Firm Storage Services revenue/Mcf	$ 0.09	$ 0.10	$ 0.13	$ 0.13	$ 0.14	$ 0.14
Average monthly Hub Services revenue/Mcf	$ 0.01	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Adjusted EBITDA/Mcf	$ 1.14	$ 1.14	$ 1.11	$ 0.72	$ 0.28	$ 0.97

(1) At December 31, 2009 on a historical basis, the long-term debt and total debt balances consist of an intercompany note payable to PAA. At December 31, 2009 on a pro forma basis, the long-term debt and total debt balances consist of borrowings under our new revolving credit facility.

(2) Adjusted EBITDA and distributable cash flow are defined in Non-GAAP and Segment Financial Measures below.

(3) The successor period includes total expenses of approximately $1 million associated with increased personnel costs, including added staffing, and accelerated audit and other costs related to our increased acquisition activities and our efforts to become a publicly traded entity as well as increased overhead allocations from PAA.

(4) Calculated as the sum of the capacity at the end of each month divided by the number of months in the period.

(5) Includes up to 3 Bcf of storage capacity under lease from third parties.

Non-GAAP and Segment Financial Measures

Adjusted EBITDA and distributable cash flow are supplemental financial measures that are used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring.

Adjusted EBITDA may be used to assess:

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

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

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

Distributable cash flow will be determined by our general partner and is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received.

Distributable cash flow may be used to assess our ability to generate sufficient cash flow to make distributions of the minimum quarterly distribution on all of our outstanding units as well as to satisfy the tests necessary for the conversion of our Series B subordinated units into Series A subordinated units or common

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units and the conversion of our Series A subordinated units into common units. However, distributable cash flow does not reflect actual cash on hand that is available for distribution to our unitholders.

For a discussion of the limitations on our cash distributions and our general partner s ability to change our cash distribution policy, please read Our Cash Distribution Policy and Restrictions on Distributions General Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy.

The GAAP measure most directly comparable to Adjusted EBITDA and distributable cash flow is net income. The supplemental measures of Adjusted EBITDA and distributable cash flow should not be considered as alternatives to GAAP net income. These measures have important limitations as an analytical tool because they exclude some but not all items that affect net income. You should not consider Adjusted EBITDA or distributable cash flow in isolation or as a substitute for net income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Management compensates for the limitations of Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measure, understanding the differences between such measures and net income, and incorporating this knowledge into its decision-making processes. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

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The following table presents a reconciliation of each of these supplemental financial measures of Adjusted EBITDA and distributable cash flow to the GAAP financial measure of net income on a historical and pro forma basis.

	Predecessor					Successor	Pro Forma
	August 18, through December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1 through September 2, 2009	September 3 through December 31, 2009	Year Ended December 31, 2009
				($ in thousands)			
Adjusted EBITDA reconciliation							
Net income	$ 1,696	$ 12,713	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 23,999
Income tax expense				887	473		473
Interest expense, net of amounts capitalized	1,684	8,389	7,108	4,941	4,352	4,262	759
Depreciation, depletion and amortization	1,223	3,986	4,520	6,245	8,054	3,578	12,242
Selected items impacting EBITDA							
Equity compensation expense		515	553	(110)	304	1,467	1,771
Mark-to-market of open derivative positions		1,792	(524)	(548)		370	370
Adjusted EBITDA	**$ 4,603**	**$ 27,395**	**$ 29,663**	**$ 31,001**	**$ 28,701**	**$ 12,165**	**$ 39,614**
Distributable cash flow reconciliation							
Net income	$ 1,696	$ 12,713	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 23,999
Depreciation, depletion and amortization	1,223	3,986	4,520	6,245	8,054	3,578	12,242
Income tax expense				887	473		473
Maintenance capital expenditures				(377)	(384)	(320)	(704)
Other non-cash items:							
Non-cash equity compensation expense		515	154	(216)	304	1,084	1,388
Mark-to-market of open derivative		1,792	(524)	(548)		370	370

positions

Distributable cash flow	**$ 2,919**	**$ 19,006**	**$ 22,156**	**$ 25,577**	**$ 23,965**	**$ 7,200**	**$ 37,768**

RISK FACTORS

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 prospectus 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 adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and you could lose all or part of your investment in us.

Risks Related to Our Business

We may not have sufficient cash following the establishment of reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to holders of our common units and Series A subordinated units.

In order to pay the minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit per quarter, or $1.35 per common unit and Series A subordinated unit per year, we will require available cash of approximately $15.7 million per quarter, or $62.7 million per year, based on the number of common units and Series A subordinated units to be outstanding immediately after completion of this offering, regardless of whether or not the underwriters exercise their option to purchase additional common units. We may not have sufficient available cash from distributable cash flow each quarter to enable us to pay the minimum quarterly 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 rates we charge for storage services and the amount of natural gas storage services our customers purchase from us;

- the overall balance between the supply of and demand for natural gas, on a seasonal and long-term basis, which impacts the level of demand for the natural gas storage services we provide and the rates we are able to charge for such services;

- regulatory action affecting the rates we can charge for the services we provide, the demand for natural gas, the supply of natural gas, how we contract for services, our existing contracts, our operating and capital costs and our operating flexibility;

- the creditworthiness of our customers;

- the level of competition from other providers of natural gas storage services;

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

- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the cost of acquisitions;
- 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.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read Our Cash Distribution Policy and Restrictions on Distributions.

On a pro forma basis, we would not have had sufficient available cash from distributable cash flow to pay the full minimum quarterly distribution on our common units or any distributions on our Series A subordinated units for the year ended December 31, 2009.

The amount of available cash from distributable cash flow we need to pay the minimum quarterly distribution for four quarters on all of our common units and Series A subordinated units outstanding immediately after this offering is approximately $62.7 million. The amount of our pro forma available cash from distributable cash flow generated during the year ended December 31, 2009 would have been sufficient to allow us to pay only approximately 82.6% of the minimum quarterly distribution on our common units during this period and would not have been sufficient to pay any distributions on our Series A subordinated units during this period. For a calculation of our ability to make distributions to unitholders based on our pro forma results for the year ended December 31, 2009 and for the twelve months ending June 30, 2011, please read, Our Cash Distribution Policy and Restrictions on Distributions.

The amount of cash we have available for distribution to holders of our common units and Series A subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us 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 flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

The assumptions underlying our minimum estimated available cash from distributable cash flow included in Our Cash Distribution Policy and Restrictions on Distributions involve inherent and significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated.

Our estimate of available cash from distributable cash flow set forth in Our Cash Distribution Policy and Restrictions on Distributions has been prepared by management, and we have not received an opinion or report on it from our or any other independent registered public accounting firm. The assumptions underlying the forecast are inherently uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve the forecasted results, we may not be able to pay the full minimum quarterly distribution or any amount on our common units or Series A subordinated units, in which event the market price of our common units may decline materially. For further discussion on our ability to pay our minimum quarterly distribution, please read Our Cash Distribution Policy and Restrictions on Distributions.

Increased competition from other companies that provide natural gas storage services or services that can substitute for storage services could have a negative impact on the demand for our services, which could adversely affect our financial results.

We compete primarily with other providers of natural gas storage services who own or operate salt-dome, depleted reservoir and/or converted aquifer gas storage facilities. Such competitors include independent storage developers and operators, local distribution companies, utilities, interstate and intrastate gas transmission companies with storage facilities connected to their pipelines and midstream energy companies. FERC has adopted policies that favor the development of new storage projects and there are numerous projects, including expansions of existing facilities and greenfield construction projects, at various stages of development in the markets where Pine Prairie and Bluewater operate. According to FERC data, since 2000, permits have been issued by the FERC for new interstate gas storage facilities or expansions in the Gulf Coast (excluding intrastate facilities and FERC pre-filings for additional storage capacity) representing aggregate additional working gas capacity of approximately 576 Bcf. These projects, if developed and placed into service, may compete with our storage operations. The principal elements of competition among storage facilities are rates, terms of service, types of service, deliverability, supply and market access, flexibility and reliability of service.

We also compete with certain pipelines, marketers and LNG facilities that provide services that can substitute for certain of the storage services we offer. In addition, natural gas as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas storage services.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers as we seek to expand our business. This could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas storage in our markets, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

Our natural gas storage operations are subject to regulation by federal, state and local regulatory authorities; regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Our natural gas storage operations are subject to federal, state and local laws and regulations administered by a number of authorities. Because we store natural gas that is transported in interstate commerce, our natural gas storage facilities are subject to comprehensive regulation by the FERC under the Natural Gas Act of 1938, or NGA. Federal regulation under the NGA extends to such matters as:

- rates, operating terms and conditions of service;
- the form of tariffs governing service;
- the types of services we may offer to our customers;
- the certification and construction of new, or the expansion of existing, facilities;
- the acquisition, extension, disposition or abandonment of facilities;
- contracts for service between storage providers and their customers;
- creditworthiness and credit support requirements;
- the maintenance of accounts and records;
- relationships among affiliated companies involved in certain aspects of the natural gas business;
- the initiation and discontinuation of services; and
- various other matters.

The NGA requires that tariff rates for our interstate gas storage facilities be just and reasonable. In addition, under the NGA and applicable FERC regulations, we are prohibited from unduly preferring or unreasonably discriminating against any person with respect to rates or terms and conditions of service.

The rates and terms and conditions for interstate services provided by our Pine Prairie and Bluewater facilities are set forth in FERC-approved tariffs, which currently permit both Pine Prairie and Bluewater to charge market-based rates. Market-based rate authority allows Pine Prairie and Bluewater to negotiate rates with individual customers based on market demand. This right to charge market-based rates may be challenged by a party filing a complaint with FERC. Our market-based rate authorization may also be re-examined if we add substantial new storage capacity through expansion or acquisition and as a result obtain market power. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing storage services.

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 Energy Policy Act of 2005, or EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for certain violations of up to $1,000,000 per day for each violation. FERC also has the authority to order disgorgement of profits from transactions deemed to violate the NGA and the EPAct 2005. Please read Business Regulation.

Finally, new rules, regulations or laws may be passed or implemented that impose additional costs, burdens or restrictions on us. We cannot give any assurance regarding the likelihood of such future rules, regulations or laws or the effect they could have on our business, financial condition, results of operations or ability to make distributions to you.

Pine Prairie s and Bluewater s authorizations to charge market-based rates are subject to the continued existence of certain conditions related to these facilities competitive position in their respective markets and, if those conditions change, the right to charge market-based rates could be terminated.

The rates Pine Prairie and Bluewater charge for storage services are regulated by FERC pursuant to its market-based rate policy, which allows regulated entities to charge rates different from, and in some cases, less than, those which would be permitted under traditional cost-of-service regulation. Pine Prairie s and Bluewater s authorization to charge market-based rates is based on determinations by FERC that neither Pine Prairie nor Bluewater have market power in their respective markets. The determination that storage facilities lack market power is subject to review and revision by FERC if there is a change in circumstances that could affect the ability of additional storage or interconnected pipeline facilities at Pine Prairie or Bluewater to exercise market power. Among the sorts of changes in circumstances that could raise market power concerns would be an expansion of Pine Prairie s or Bluewater s capacity, acquisitions, or other changes in market dynamics. If the FERC were to conclude that Pine Prairie or Bluewater may have acquired and cannot mitigate market power, their rates could become subject to cost-of-service regulation.

If Pine Prairie or Bluewater s rates become subject to cost-of-service regulation, the maximum rates that may be charged for storage services would be established through FERC s ratemaking process, and Pine Prairie or Bluewater would no longer be able to charge a rate demanded by the market. Generally, cost-of-service based rates for interstate natural gas services are based on the cost of providing service including recovery of, and a reasonable return on, the entity s actual prudent historical cost investment for providing jurisdictional service. Key determinants in the ratemaking process are costs of providing service, allowed rate of return, and billing determinants, which are based upon storage volumes and contractual capacity commitment assumptions. Rate design and the allocation of costs underlying cost-of-service based rates must also be approved by FERC as part of each rate case. The resolution of these key determinants, particularly the allowed rate of return and billing determinants that would underlie the cost-of-service based rates through the FERC s ratemaking process, could adversely impact Pine Prairie or Bluewater s profitability, and have adverse consequences on our cash flow and our ability to make distributions. Additionally, changes in generally applicable FERC ratemaking policies could also affect Bluewater and Pine Prairie.

Certain risks are amplified by the current economic environment.

During 2007, the U.S. and many key countries began to exhibit signs of economic weakness, which continued throughout 2008 and 2009, and into 2010. This weakness had a severe adverse impact on the global financial system, stressing a number of large financial institutions to the point of failure, merger or requiring government assistance and resulting in a severe reduction in available capital. Capital constraints coupled with significant energy price volatility have produced pervasive liquidity issues for many companies. Such events have created pronounced uncertainty in the economic outlook, and have amplified the potential impact and likelihood of the occurrence of certain risks inherent in our business. Such amplified risks include:

- increased cost of capital and increased difficulties accessing capital to fund expansion and acquisition activities as well as routine operating requirements;

the inability or unwillingness of lenders to honor their contractual commitments;

the failure of customers to timely or fully pay amounts due to us;

the failure of suppliers to pay third parties under obligations for which we have potential contingent liabilities;

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- the potential for adverse actions by rating agencies;
- potentially adverse changes in tax laws;
- the failure of counterparties to fulfill their delivery or purchase obligations; and
- business failures by vendors, suppliers or customers.

Any significant and prolonged change in or stabilization of natural gas prices could have a negative impact on our business.

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The storage business has benefited from significant price fluctuations resulting from seasonal price sensitivity, which impacts the level of demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If volatility and seasonality in the natural gas industry decrease, because of increased production capacity or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline.

In addition to volatility and seasonality, an extended period of high gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated expansion activities. An extended period of low natural gas prices could adversely impact storage values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business and financial results.

We may not be able to maintain or replace expiring storage contracts.

Our primary exposure to market risk occurs at the time our existing storage contracts expire and are subject to renegotiation and renewal. As of April 1, 2010, the weighted average remaining tenor of our existing portfolio of firm storage contracts is approximately 3.7 years at Pine Prairie and approximately 2.2 years at Bluewater. For the year ended December 31, 2009, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 17% and 13% of our revenues, respectively. The extension or replacement of existing contracts, including our contracts with Iberdrola Renewables, Inc. and Guardian Pipeline, LLC, depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide storage services to our markets;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

Any failure to extend or replace a significant portion of our existing contracts, or extending or replacing them at unfavorable or lower rates, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Our storage business depends on third-party pipelines connected to our storage facilities, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such pipelines.

We depend on the continued operation of third-party pipelines and other facilities that provide delivery options to and from our storage facilities. For example, at our Pine Prairie facility, we have nine separate interconnect points with eight different interstate pipelines, and at our Bluewater facility, we are connected to three interstate and three natural gas utility pipelines. Because we do not own the pipelines that are interconnected to our facilities, their continued operation is not within our control. If any of the pipelines to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the facility, lack of capacity or any other reason, our ability to operate efficiently and satisfy our customers needs could be compromised, thereby potentially reducing our revenues. Any temporary or permanent interruption at any key pipeline or other interconnect point with our gas storage facilities that caused a material reduction in the volume of storage services provided by us could have a material adverse effect on our business, financial condition, results of operation and ability to make distributions.

In addition, the rates charged by pipelines interconnected with our storage facilities for transportation to and from our facilities affects the utilization and value of the storage services we provide. Significant changes in the rates charged by these pipelines or their competitors could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

We may not be able to achieve our current expansion plans at our Pine Prairie facility on economically viable terms.

Our current expansion plans include the addition of 31 Bcf of working gas storage capacity at our Pine Prairie facility, 28 Bcf of which we expect to place into service by mid-2012, including 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. In connection with these expansion efforts, we may encounter difficulties in the drilling required to access subsurface storage caverns, the drilling of raw water wells or salt water disposal wells and the completion of the wells. These risks include the following:

- unexpected operational events;
- adverse weather conditions;
- facility or equipment malfunctions or breakdowns;
- unusual or unexpected geological formations;
- drill bit or drill pipe difficulties;
- collapses of wellbore, casing or other tubulars or other loss of drilling hole;
- unexpected problems associated with filling the caverns with base gas and conducting pressure and mechanical integrity tests;
- unexpected problems associated with leaching the caverns, filtration of extracted water and offsite disposal of water; and
- risks associated with subcontractors services, supplies, cost escalation and personnel.

Specifically, the creation of a salt-cavern storage facility requires sourcing, injecting, withdrawing and disposing of significant volume of water. For example, to create 10 Bcf of working capacity, a salt cavern requires approximately 72 million barrels of raw water supply and an equivalent volume of salt water disposal. Additionally, the rate of access to raw water and the rate of disposal of salt water have a direct impact on the time it takes to create a salt cavern. Any physical or regulatory restriction imposed on our current operations with respect to accessing raw water or disposing of salt water would have an adverse impact on our ability to timely and fully expand our facility at Pine Prairie. During the initial construction of Pine Prairie, we encountered challenges related to many of the factors listed above and specifically with respect to the ability to efficiently dispose of salt water, all of which resulted in substantial delays and the incurrence of significant costs in excess of our original estimates. There can be no assurance that we will not encounter similar situations in the future or that our ability to access raw water or dispose of salt water will not be adversely impacted in the future. Additionally, the occurrence of uninsured or under-insured losses, delays or operating cost overruns associated with these drilling efforts could have a negative impact on our operations and financial results.

We may not be able to increase the capacity of our Pine Prairie facility beyond our current expansion plans.

While we have both the property rights and operational capacity necessary to expand our Pine Prairie facility beyond the currently permitted capacity of 48 Bcf to a potential of over 150 Bcf of total working gas storage capacity, we may not be able to secure the financing or permits necessary to pursue such expansion and the necessary infrastructure modifications that would be needed to accommodate such expansion. Additionally, such expansion will be subject to market demand, the successful execution of any expansion projects and the availability of sufficient third-party interstate and intrastate pipelines receipt and deliverability capacity to accommodate the increased capacity. Any combination of these factors may prevent us from expanding our Pine Prairie facility beyond its current permitted capacity.

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We are exposed to the credit risk of our customers in the ordinary course of our business.

As a normal part of our business we extend credit to our customers. As a result, we are exposed to the risk of loss resulting from the nonpayment and/or nonperformance of our customers. While we have established credit policies that include assessing the creditworthiness of our customers as permitted by Pine Prairie s and Bluewater s tariffs and requiring appropriate terms or credit support from them based on the results of such assessments, there can be no assurance that we have adequately assessed the creditworthiness of our existing or future customers or that there will not be unanticipated deterioration in their creditworthiness. Resulting nonpayment and/or nonperformance by our customers could have a material adverse effect on our business, financial condition, results of operation and ability to make distributions.

Additionally, in instances where we loan natural gas to third parties, the magnitude of our credit risk is significantly increased, as the failure of the third party to return the loaned volumes would result in losses equal to the full value of the loaned natural gas rather than, in the case of firm storage or hub services contracts, losses equal to fees on volumes nominated for injection or withdrawal.

For various operating and commercial reasons, we may not be able to perform all of our obligations under our contracts, which could lead to increased costs and negatively impact our financial results.

Various operational and commercial factors could result in an inability on our part to satisfy our contractual commitments and obligations. For example, in connection with our provision of firm storage services and hub services to our customers, we enter into contracts that obligate us to honor our customers requests to inject gas into our storage facilities, withdraw gas from our facilities and wheel gas through our facilities, in each case subject to volume, timing and other limitations set forth in such contracts. The following factors could adversely impact our ability to perform our obligations under these contracts:

- a failure on the part of our storage facilities to perform as we expect them to, whether due to malfunction of equipment or facilities or realization of other operational risks;

- the operating pressure of our storage facilities:

  - the operating pressure of our depleted reservoir storage facilities is driven primarily by the total volume of working and base gas contained in the reservoir, which depends primarily on the amount of base gas purchased by us and injected into the facility, the amount of base gas we may have loaned to third parties and the aggregate injection or withdrawal demands of our customers; and

  - the operating pressure of our salt-cavern storage facilities is directly affected by the volume and temperature of natural gas within each facility. The total volume of gas in our salt caverns is driven by the same factors mentioned above for our depleted reservoirs. The temperature of the natural gas stored in a salt cavern is driven by a number of factors, including the ambient subsurface temperature for such cavern (i.e., the static subsurface temperature to which the stored gas will naturally return over time) and the rate of injection or withdrawal of gas from such cavern (due to the fact that sustained periods of high rates of withdrawal reduce the temperature of the remaining gas and sustained periods of high rates of injection have the opposite effect). Higher than normal temperatures generally equate with higher than normal pressures and require more space to store the same volume of gas and remain in compliance with maximum pressure limitations imposed by prudent operating practices or regulations. Lower than normal temperatures generally equate with lower than normal pressures and require more base gas to meet contractual withdrawal obligations and remain in compliance with minimum pressure limitations imposed by prudent operating practices or regulations;

a variety of commercial decisions we make from time to time in connection with the management and operation of our storage facilities. Examples include, without limitation, decisions with respect to matters such as (i) the aggregate amount of commitments we are willing to make with respect to wheeling, injection, and withdrawal services, which could exceed our capabilities at any given time for various reasons, (ii) the timing of scheduled and unplanned maintenance or repairs, which can impact equipment availability and capacity, (iii) the schedule for and rate at which we conduct leaching activities at our Pine Prairie facility in connection with the creation of new salt caverns or the expansion of existing caverns, which can impact the amount of storage capacity we have available to satisfy our customers requests, (iv) the timing and aggregate volume of any base gas park and/or loan transactions we consummate, which can directly affect the operating pressure of our storage facilities and (v) the amount of compression capacity and other gas handling equipment that we install at our facilities to support gas wheeling, injection and withdrawal activities; and

adverse operating conditions due to hurricanes, extreme weather events or conditions, and operational problems or issues with third party pipelines, storage or production facilities.

Although we manage and monitor all of these various factors in connection with the ongoing operation of our natural gas storage facilities with the goal of performing all of our contractual commitments and obligations and optimizing our revenue, one or more of the above factors may adversely impact our ability to satisfy our injection, withdrawal or wheeling obligations under our storage contracts. In such event, we may be liable to our customers for losses or damages they suffer and/or we may need to incur costs or expenses in order to permit us to satisfy our obligations and avoid a breach or increase our costs in doing so.

For example, if Pine Prairie experiences sustained periods of high injections as it approaches full capacity and the resulting cavern temperature and pressure would otherwise exceed the maximum operating pressure, we may be required to loan a portion of our base gas to third parties in order to create the space we need to permit us to honor our customers injection requests. In connection with any such base gas loans, we will be required to pay fees that could be significant. Conversely, if Pine Prairie experiences sustained periods of high withdrawals as customers withdraw their inventory and an abnormally low cavern temperature results in a significant reduction in pressure, we may be required to borrow gas from a third party and inject it into our facility or inject raw water into our facility, in each case in order to maintain our minimum operating pressure or create the operating pressure needed to satisfy our customers withdrawal requests. In such a circumstance we would have to (i) pay fees to a third party to borrow additional gas or (ii) incur operating costs associated with raw water injection, removal and disposal and opportunity costs associated with the temporary loss of usable storage capacity displaced by the injected water.

Our marketing activities could result in financial losses.

Without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year firm storage contracts at attractive rates, during 2010 we intend to establish a dedicated commercial marketing group that will capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. Through these transactions, we will seek to maintain a position that is substantially balanced between purchases on the one hand and sales or future delivery obligations on the other hand. Our general policy will be (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flow and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes. While we intend to conduct these transactions within these pre-defined risk parameters, these policies will not eliminate all risks. For example, any event that disrupts our anticipated physical supply of or market for natural gas could expose us to significant costs or expenses in order to enable us to satisfy our obligations to store or deliver contracted natural gas volumes.

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

Our natural gas storage operations are subject to stringent and complex federal, state and local environmental laws and regulations. We may incur substantial costs in order to conduct our operations in compliance with these laws and regulations. These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct certain activities, increases in operating expenses or curtailment of certain operations to limit or prevent releases of materials from our

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facilities, the incurrence of capital expenditures associated with the installation of pollution control equipment, and the imposition of substantial liabilities for pollution resulting from our operations. Moreover, new, stricter environmental laws, regulations or enforcement policies could be implemented that significantly increase our compliance costs or the costs of any remediation of environmental contamination that may become necessary, and these costs could be material. For example, the adoption and implementation of any climate change legislation or regulations imposing reporting obligations with respect to, or limiting emissions of, greenhouse gases could result in increased operating costs and adversely affect demand for natural gas.

Numerous governmental authorities, such as the U.S. Environmental Protection Agency 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. In addition, joint and several liability or strict liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. Private parties 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 that may result from environmental and other impacts of our operations. We may not be able to recover all or any of these costs through insurance or other means, which may have a material adverse effect on our business, financial condition, results of operation and ability to make distributions. Please read Business Environmental Matters for more information.

If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

A principal focus of our strategy is to continue to grow the cash distributions on our units by expanding our business. Our ability to grow depends on our ability to complete expansion projects and make acquisitions that result in an increase in cash generated from operations on a per unit basis (i.e., are accretive). We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- we are unable to identify attractive expansion projects or acquisition candidates that satisfy our economic and other criteria, or we are outbid for such opportunities by our competitors;
- we are unable to raise financing for such expansion projects or acquisitions on economically acceptable terms;
- we are unable to secure adequate customer commitments to use the facilities to be expanded or acquired; or
- we are unable to obtain governmental approvals or other rights, licenses or consents needed to complete such expansion projects or acquisitions.

Acquisitions or expansion projects that we complete may not perform as anticipated and could result in a reduction of our distributable cash flow on a per unit basis.

Even if we complete expansion projects or acquisitions that we believe will be accretive, such projects or acquisitions may nevertheless reduce our available cash from distributable cash flow on a per unit basis due to the following factors:

- mistaken assumptions about storage capacity, deliverability, base gas needs, geological integrity, revenues, synergies, costs (including operating and general and administrative, capital, debt and equity costs), customer demand, growth potential, assumed liabilities and other factors;

an inability to complete expansion projects on schedule and within applicable budgets due to various factors, including cost overruns, schedule delays, and the inability to obtain necessary permits or approvals;

the failure to receive cash flows from an expansion project or newly acquired asset due to delays in the commencement of operations for any reason;

unforeseen operational issues or the realization of liabilities that were not known to us at the time the acquisition or expansion project was completed;

the inability to attract new customers or retain acquired customers to the extent assumed in connection with the expansion or acquisition project;

the failure to successfully integrate expansion projects or acquired assets or businesses into our operations and/or the loss of key employees; or

the impact of regulatory, environmental, political and legal uncertainties that are beyond our control.

If we consummate any future expansion projects or acquisitions, our capitalization and results of operations may change significantly, and you 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. If any expansion projects or acquisitions we ultimately complete are not accretive to our distributable cash flow per common unit and Series A subordinated unit, our ability to make distributions may be reduced.

We could lose the benefits of the Pine Prairie tax abatement.

In May 2006, we entered into an arrangement with the Industrial Development Board No. 1 of the Parish of Evangeline, State of Louisiana, Inc. (the Industrial Development Board), pursuant to which we sold a portion of the Pine Prairie facility located in the parish to the Industrial Development Board and entered into a 15-year agreement, which commenced in January of 2008, to lease back such portion of the facility. Pursuant to this arrangement and in exchange for certain payments in lieu of taxes, we are not subject to ad valorem property tax in Evangeline Parish except for ad valorem tax on inventory. As of December 31, 2009, the present value of the tax abatement was approximately $23 million. We classify the present value of the tax abatement as an intangible asset, so if we were to lose the tax abatement due to a successful legal challenge of the arrangement, our violation of the terms of the lease, or for any other reason, it would be a charge to our earnings and could have an adverse impact on our results of operations and ability to make distributions. See Business Title to Properties and Rights-of-Way.

Our natural gas storage facilities are new and have limited operating history. The facilities may not be able to deliver as anticipated, which could prevent us from meeting our contractual obligations and cause us to incur significant costs.

Although we believe that our operating gas storage facilities at Bluewater and Pine Prairie have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, the facilities are new and have a limited operating history. If we fail to wheel, inject or withdraw natural gas at contracted rates, or cannot deliver natural gas consistent with contractual quality specifications, we could incur significant costs to satisfy our contractual obligations. These costs could have an adverse impact on our business, financial condition, results of operations and ability to make distributions.

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 the natural gas storage business, including:

- reduction of our available storage capacity at our salt caverns over time due to (i) unexpected increases in the temperature of our caverns, which reduces capacity as a result of the expansion of the stored natural gas, (ii) the long-term effect of pressure differentials between the caverns and the surrounding salt formations (known as salt creep) or (iii) problems with the structural integrity of our salt caverns;

- subsidence of the geological structures where we store natural gas;

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- risks and hazards inherent in drilling operations associated with the development of new caverns and/or the drilling of raw water wells or salt water disposal wells;
- problems maintaining the wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our storage facilities;
- impacts to our operations due to the unavailability of raw water for any reason or the inability to dispose of salt water through our salt water disposal wells for any reason;
- damage to our storage facilities, related equipment and connecting pipelines and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from third parties, including 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;
- collapse of storage caverns;
- operator error;
- environmental pollution or other environmental issues, including drinking water contamination, associated with our raw water or water disposal wells or our water treatment facilities;
- damage associated with equipment or material failures, pipeline or vessel ruptures or corrosion, explosions, fires and other incidents; and
- other hazards that could result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to breaches of contractual commitments, personal injury and/or loss of life, 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. In addition, we are not 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 result in a material adverse effect on our business, financial condition, results of operations and ability to make distributions. 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 our indemnification rights, for potential environmental liabilities.

In addition, we share insurance coverage with PAA, for which we reimburse PAA s general partner pursuant to the terms of the omnibus agreement. To the extent PAA experiences covered losses under the insurance policies, the limit of our coverage for potential losses may be decreased.

If leakage or migration of natural gas or other hydrocarbons occurs from any of our storage facilities, our operations and financial results could be adversely affected.

Our operations are subject to the risk that natural gas or other hydrocarbons could leak or migrate from our storage facilities, causing a loss of volumes stored in the storage facilities. This risk could cause substantial losses due to our inability to deliver the stored volumes back to our customers. Furthermore, we may not be able to obtain insurance to protect against this risk and we may not be able to maintain insurance of the type and amount we desire at reasonable rates to insure against this risk.

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Restrictions in our credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our units.

Our credit agreement restricts our ability to, among other things:

- make distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists or would result therefrom;
- incur additional indebtedness;
- grant or permit to exist liens or enter into certain restricted contracts;
- engage in transactions with affiliates;
- make any material change to the nature of our business;
- make a disposition of all or substantially all of our assets; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

Furthermore, our credit facility contains covenants requiring us to maintain certain financial ratios related to our consolidated EBITDA, consolidated interest charges and consolidated funded indebtedness, as such terms are defined in our credit agreement.

The provisions of our credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit facility could result in an event of default, which could enable our lenders, subject to the terms and conditions of the anticipated credit facility, to declare any outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If the payment of any such debt is accelerated, our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment.

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

Our future level of debt 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 flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

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

For more information regarding our debt agreements, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

We are considered a subsidiary of PAA under its debt instruments and, as such, we may be directly or indirectly subject to and impacted by certain restrictions in PAA s existing and future credit facilities and indentures. These restrictions may limit our access to credit, prevent us from engaging in beneficial activities, and in certain circumstances, require us to guarantee PAA s indebtedness.

Although we are not contractually bound by and are not liable for PAA s debt under its debt instruments, we are subject to and indirectly affected by certain prohibitions and limitations contained therein. Such restrictions may prevent us from obtaining the most advantageous financing terms or from engaging in certain transactions that might otherwise be considered beneficial. For example (by reference to the most restrictive of any applicable covenant):

We will be restricted from entering into any future sale/leaseback transactions.

PAA is subject to a limit of 10% of PAA s consolidated net tangible assets with respect to the amount of debt that can be secured by liens on facilities owned by its subsidiaries, including us. We cannot control the incurrence of secured debt by PAA s other subsidiaries.

We cannot give intercompany guaranties of debt for borrowed money for the benefit of PAA or any subsidiary of PAA (including any of our subsidiaries) unless we agree to guarantee PAA s outstanding debt. The same restriction would apply to a guaranty of our debt by one of our subsidiaries.

Although we believe that the restrictions in PAA s debt instruments will not have a material impact on our operations or access to credit, no assurance can be given to that effect, and PAA s ability to comply with any restrictions in PAA s debt instruments may be affected by events beyond our control.

Any debt instruments that PAA or any of its affiliates enters into in the future, including any amendments to existing credit facilities, may include additional or more restrictive limitations on our ability to conduct our business. These additional restrictions could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities. In addition, PAA has the ability to prevent us from taking actions that would cause PAA to violate any covenants in its credit facilities or indentures, or otherwise to be in default under any of its debt instruments. In deciding whether to prevent us from taking any such action, PAA will have no fiduciary duty to us or our unitholders.

The credit and risk profile of our general partner and its owner, PAA, could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

The credit and business risk profiles of our general partner and PAA may be factors considered in credit evaluations of us. This is because our general partner, which is owned by PAA, controls our business activities, including our cash distribution policy and expansion strategy. Any adverse change in the financial condition of PAA, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness, may adversely affect our credit ratings and risk profile.

If we were to seek a credit rating in the future, our credit rating may be adversely affected by the leverage of our general partner or PAA, as credit rating agencies such as Standard & Poor s Ratings Services and Moody s Investors Service may consider the leverage and credit profile of PAA and its affiliates because of their ownership interest in and control of us. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make distributions to unitholders.

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 on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and our 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 to make cash distributions at our intended levels.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

Prior to this offering, we have not been required to file reports with the SEC. Upon the completion of this offering, we will become subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 for our fiscal year ending December 31, 2011. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm s, conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

Risks Inherent in an Investment in Us

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

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement 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.

Cost reimbursements due to PAA s general partner 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 you. The amount and timing of such reimbursements will be determined by PAA s general partner.

Prior to making distributions on our common units, we will reimburse PAA s general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by PAA, its general partner or our general partner in managing and operating us. These operating expense reimbursements and the reimbursement of incremental general and administrative expenses we will incur as a result of

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becoming a publicly traded partnership are not capped. In addition, PAA and our general partner will have substantial discretion in incurring third-party expenses on our behalf. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursements to PAA s general partner and our general partner will reduce the amount of cash otherwise available for distribution to our unitholders.

Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights, without the approval of the conflicts 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 Series A subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) 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 each target distribution level will be reset to the correspondingly higher amount that causes such reset target distribution level to exceed the reset minimum quarterly distribution by the same percentage that such distribution level exceeds the then-current minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and will retain its then-current general partner interest. The number of common units to be issued to our general partner will equal the 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. 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 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 common units to our general partner in connection with resetting the target distribution levels. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions General Partner s Right to Reset Target Distribution Levels.

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 you 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.

Your 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 other states. The

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limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some states in which we do business or may do business in from time to time in the future. You could be liable for any and all of our obligations as if you 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

- your 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 constitutes control of our business.

For a discussion of the implications of the limitations of liability on a unitholder, please read The Partnership Agreement Limited Liability.

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

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 the directors of our general partner. The board of directors of our general partner will be chosen by PAA. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

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

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates will own sufficient units upon completion of this offering to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding units voting together as a single class is required to remove our general partner. Following the closing of this offering, PAA will own an aggregate of approximately 79.4% of our outstanding limited partner 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 Series A subordinated units and Series B 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 then-existing common units by prematurely eliminating their distribution and liquidation preference over our Series A subordinated units and Series B subordinated units, which would otherwise have continued until we had met certain distribution, performance and operational 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 unitholder s 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 Series A subordinated units and Series B subordinated units to common units.

Our partnership agreement restricts the voting rights of 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 PAA 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 may 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.

Upon closing of the offering, investors in our common units will experience immediate and substantial dilution in pro forma net tangible book value of $10.56 per common unit.

The initial public offering price of $21.50 per common unit exceeds our pro forma net tangible book value of $10.94 per common unit. Based on the initial public offering price of $21.50 per common unit, you will incur immediate and substantial dilution of $10.56 per common unit. This dilution results primarily because the assets contributed by our general partner and its affiliates are recorded in accordance with GAAP at their book value, and not their fair value. Please read Dilution.

We may issue additional units without your approval, which would dilute your 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 Series A 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.

PAA 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.

After the sale of the common units offered by this prospectus, assuming that the underwriters do not exercise their option to purchase additional common units, PAA will hold 19,864,529 common units, 13,934,351 Series A subordinated units and 11,500,000 Series B subordinated units. All of the Series A subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. The

Series B subordinated units are also eligible for conversion into common units if certain operational and financial conditions are satisfied and the end of the subordination period has occurred. The sale 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 that may develop. A sale or transfer, including certain deemed transfers, by PAA of all or portions of its interests in us may cause our partnership to terminate for federal income tax purposes. For a discussion of the impact this could have on common unitholders, please read Tax Risks to Common Unitholders 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.

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and you could lose all or part of your investment.

Prior to this offering, there has been no public market for our common units. After this offering, there will be only 11,720,000 publicly traded common units, assuming no exercise of the underwriters option to purchase additional common units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. You may not be able to resell your common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for the common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units after this offering or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these Risk Factors.

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses. In addition, the Sarbanes-Oxley Act of 2002 and related rules subsequently implemented by the SEC and the NYSE have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded partnership reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and to possibly result in our general partner having to accept reduced policy limits and coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers. We have included $2.6 million of estimated incremental costs per year associated with being a publicly traded partnership in our financial forecast included elsewhere in this prospectus. However, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

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Risks Related to Conflicts of Interest

PAA owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. PAA and our general partner have conflicts of interest and may favor PAA s interests to your detriment.

Following this offering, PAA will own and control our general partner, as well as appoint all of the officers and directors of our general partner, and some of the officers of our general partner are also officers of PAA s general partner (and one such officer is also a member of the board of directors of PAA s general partner). Although our general partner has a legal 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 legal duty to manage our general partner in a manner that is beneficial to its owner, PAA. Conflicts of interest may arise between PAA 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 PAA 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 PAA to pursue a business strategy that favors us. Directors and officers of PAA s general partner have legal duties to make these decisions in the best interests of the owners of PAA, which may be contrary to our interests;

- while PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business, PAA and its affiliates are not limited in their ability to compete with us;

- our general partner is allowed to take into account the interests of parties other than us, such as PAA, in resolving conflicts of interest;

- certain of the officers of our general partner will also devote significant time to the business of PAA and will be compensated by PAA s general partner accordingly;

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

- our partnership agreement contains provisions designed to facilitate PAA s ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders;

- 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, issuances of additional partnership securities and the creation, reduction or increase of cash reserves. Each of these determinations can affect the amount of cash that is distributed to our unitholders and to our general partner, the ability of the Series A subordinated units to convert to common units and the achievement of the financial conditions necessary for the Series B subordinated units to convert to Series A subordinated units or common units;

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 distributable cash flow. These determinations can affect the amount of cash that is distributed to our unitholders and to our general partner, the ability of the Series A subordinated units to convert to common units and the Series B subordinated units to convert to Series A subordinated units or common units;

our general partner will determine the amount and timing of the planned expansions of our Pine Prairie facility, and as a result, the achievement of the operational conditions necessary for the Series B subordinated units to convert to Series A subordinated units or common units, as applicable;

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 Series A subordinated units, to make incentive distributions or to make distributions to achieve the financial conditions necessary for the Series B subordinated units to convert to Series A subordinated units for the Series A subordinated units to convert to common units;

our partnership agreement permits us to distribute up to $40 million from capital sources without treating such distribution as a distribution from capital;

our general partner determines which costs incurred by it are reimbursable by us;

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

our general partner intends to limit its liability regarding our contractual and other obligations;

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

our general partner controls the enforcement of the obligations that it and its affiliates owe to us;

our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and

our general partner may elect to cause us to issue common 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 conflicts 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 Conflicts of Interest and Fiduciary Duties.

PAA may engage in competition with us.

Although PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business, PAA and its affiliates are not limited in their ability to compete with us.

Our partnership agreement defines and modifies the duties of our general partner and restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner.

Our partnership agreement contains provisions that define the standard of care that our general partner must exercise and restrict the remedies available to unitholders for actions taken by our general partner in accordance with that standard of care, including in circumstances that might otherwise be challenged under state law standards. 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. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples of decisions that our general partner may make in its individual capacity include:

(a) how to allocate corporate opportunities among us and our general partner s affiliates;

(b) whether to exercise its limited call right;

(c) how to exercise its voting rights with respect to the units it owns;

(d) whether to exercise its registration rights;

(e) whether to elect to reset target distribution levels; and

(f) whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

provides that whenever our general partner makes a determination, including any determination with respect to distributable cash flow or any components thereof, 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 subjectively believed that the decision was (i) with respect to matters involving us, in, or not opposed to, the best interests of our partnership and (ii) with respect to matters involving the relative rights and privileges of holders of our equity interests, consistent with the intent of the provisions of our partnership agreement;

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;

generally provides that any resolution or course of action adopted by our general partner and its affiliates in respect of a conflict of interest will be permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any duty stated or implied by law or equity if the resolution or course of action in respect of such conflict of interest is:

(a) approved by the conflicts committee of our general partner after due inquiry, based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us;

(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, directors and executive officers;

(c) determined by our general partner (after due inquiry) to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(d) approved by our general partner (after due inquiry) based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us, which may include taking into account the totality of the circumstances and relationships involved (our short-term or long-term interests and other arrangements or relationships that could be considered favorable or advantageous to us); and

provides that, to the fullest extent permitted by law, in connection with any action or inaction of, or determination made by, our general partner s board of directors or its conflicts committee with respect to any matter relating to us, it shall be presumed that our general partner s board of directors or its conflicts committee acted in a manner that satisfied the contractual standards set forth in our partnership agreement, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or our partnership challenging any such action or inaction of, or determination made by, our general partner, the person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions of the partnership agreement, including the provisions discussed above. Please read Conflicts of Interest and Fiduciary Duties Duties of our General Partner.

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Our general partner intends to limit its liability regarding our obligations.

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

Our general partner has a limited call right that may require you to sell your 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, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. At the closing of this offering, and assuming no exercise of the underwriters option to purchase additional common units, PAA will own approximately 62.9% 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 Series A subordinated units), PAA will own approximately 74.3% of our outstanding common units. Upon the satisfaction of certain operational and financial conditions and the end of the subordination period having occurred, assuming no additional issuances of common units (other than upon the conversion of the Series A subordinated units and the ultimate conversion of the Series B subordinated units to common units), PAA will own approximately 79.4% of our outstanding common units. For additional information about this right, please read The Partnership Agreement Limited Call Right.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, you should read Material Income Tax Consequences for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

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 additional entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you 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, and do not plan to request, a ruling from the Internal Revenue Service, or the IRS, on this or any other tax matter affecting us.

Despite the fact that we are classified as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe, based upon our current operations, that we will be so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow 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 entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Specifically, we will be subject to an entity-level tax on any portion of our income that is generated in Texas in the prior year. Imposition of any such additional taxes on us 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 income tax purposes, our target distribution amounts will be adjusted to reflect the impact of that law on us.

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 (i) publicly traded partnerships or (ii) an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of (i) publicly traded partnerships, including us, or (ii) an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Although the considered legislation would not appear to have affected our treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

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. Immediately following this offering, PAA will own more than 50% of the total interests in our capital and profits interests. Therefore, a transfer by PAA of all or a portion of its interests in us, including a deemed transfer as a result of a termination of PAA s partnership for federal income tax purposes, could result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year

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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 his 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. Please read Material Income Tax Consequences Disposition of Common Units Constructive Termination for a discussion of the consequences of our termination for federal income tax purposes.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your 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 you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read Material Income Tax Consequences Disposition of Common Units Recognition of Gain or Loss for a further discussion of the foregoing.

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 (known as 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 will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. 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.

We will 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 will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please

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read Material Income Tax Consequences Tax Consequences of Unit Ownership Section 754 Election for a further discussion of the effect of the depreciation and amortization positions we adopt.

We will adopt 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.

We will 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 generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships 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, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

A unitholder whose common units are 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, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there is no tax concept of loaning a partnership interest, 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 units. In that case, he 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 should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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You will likely be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you will likely be 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 you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We will initially own assets and conduct business in the states of Louisiana and Michigan. Each of these states currently imposes a personal income tax and also impose income taxes on corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all 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.

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USE OF PROCEEDS

We expect to receive net proceeds of approximately $236.5 million, after deducting underwriting discounts and commissions but before paying offering expenses, from the issuance and sale of 11,720,000 common units offered by this prospectus. We expect to use these net proceeds, together with $200 million of borrowings under our new credit facility, to repay intercompany indebtedness owed to PAA in the amount of approximately $433.9 million. PAA expects to use all or a portion of these proceeds to repay amounts outstanding under its credit facilities and for general partnership purposes.

As of December 31, 2009, we had approximately $451 million of intercompany indebtedness outstanding to PAA with a fixed interest rate of 6.5% incurred to refinance project debt and for capital expenditures. We expect that any intercompany indebtedness not repaid in connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us.

The proceeds from any exercise of the underwriters option to purchase additional common units will be used to reimburse PAA for capital expenditures it incurred with respect to the assets contributed to us. If the underwriters do not exercise their option to purchase additional common units, we will issue 1,758,000 common units to PAA at the expiration of the option period. If and to the extent the underwriters exercise their option to purchase additional common units, the number of units purchased by the underwriters pursuant to such exercise will be issued to the public and the remainder, if any, will be issued to PAA. Accordingly, the exercise of the underwriters option will not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all units. Please read Underwriting.

Affiliates of Barclays Capital Inc., UBS Securities LLC, Citigroup Global Markets Inc., Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, J.P. Morgan Securities Inc., Raymond James & Associates, Inc., Morgan Keegan & Company, Inc. and RBC Capital Markets Corporation are lenders under PAA s credit facilities and will receive their proportionate share of any repayment by PAA of its credit facilities in connection with this transaction.

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CAPITALIZATION

The following table shows:

our historical capitalization as of December 31, 2009; and

our as adjusted capitalization as of December 31, 2009, reflecting this offering of 11,720,000 common units at an initial public offering price of $21.50, the other formation transactions described under Summary Formation Transactions and Partnership Structure and the application of the net proceeds from this offering as described under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of December 31, 2009	
	Historical[1]	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 3,124	$ 724
Revolving credit facility		200,000
Note payable to PAA	450,523	
Total debt	450,523	200,000
Members equity/partners capital	432,744	683,267
Total capitalization	$ 883,267	$ 883,267

(1) Historical balances as of December 31, 2009 are those of our predecessor, PAA Natural Gas Storage, LLC.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common units sold in this offering will exceed the pro forma net tangible book value per common unit after the offering. On a pro forma basis as of December 31, 2009, after giving effect to the offering of common units and the application of the related net proceeds, and assuming the underwriters option to purchase additional common units is not exercised, our net tangible book value was approximately $636.3 million, or $10.94 per unit. Net tangible book value excludes $47 million of net goodwill and intangible assets. Purchasers of common units in this offering will experience immediate and substantial dilution in net tangible book value per common unit for financial accounting purposes, as illustrated in the following table:

Initial public offering price per common unit		$ 21.50
Net tangible book value per unit before the offering(1)	$ 8.71	
Increase in net tangible book value per unit attributable to purchasers in the offering	2.23	
Less: Pro forma net tangible book value per unit after the offering(2)		10.94
Immediate dilution in net tangible book value per common unit to purchasers in the offering(3)		$ 10.56

(1) Determined by dividing the number of units (19,864,529 common units, 13,934,351 Series A subordinated units, 11,500,000 Series B subordinated units and the corresponding value for the 2.0% general partner interest to be issued to our general partner and its affiliates, including PAA, for the contribution of assets and liabilities to us) into the net tangible book value of the contributed assets and liabilities. Amount reflects inclusion of approximately $16.6 million of intercompany indebtedness to PAA which will be converted to equity in connection with the offering.

(2) Determined by dividing the total number of units to be outstanding after the offering (31,584,529 common units, 13,934,351 Series A subordinated units,11,500,000 Series B subordinated units and the corresponding value for the 2.0% general partner interest) into our pro forma net tangible book value, after giving effect to the application of the expected net proceeds of the offering.

(3) Because the total number of units outstanding following this offering will not be impacted by any exercise of the underwriters option to purchase additional common units and any net proceeds from such exercise will not be retained by the Partnership, there will be no change to the dilution in net tangible book value per common unit to purchasers in the offering due to any such exercise of the option.

The following table sets forth the number of units that we will issue and the total consideration contributed to us by our general partner and PAA and by the purchasers of common units in this offering upon consummation of the transactions contemplated by this prospectus:

	Units Acquired		Total Consideration	
	Number	Percent	Amount	Percent

			(in thousands)	
General partner and PAA[1][2][3]	45,298,880	79.4%	$ 449,357	64.1%
Purchasers in the offering	11,720,000	20.6%	$ 251,980	35.9%
Total	57,018,880	100.0%	$ 701,337	100.0%

(1) The units acquired by our general partner and PAA consist of 19,864,529 common units, 13,934,351 Series A subordinated units and 11,500,000 Series B subordinated units. Our general partner also owns a 2.0% general partner interest in us.

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(2) The assets contributed by our general partner and its subsidiaries were recorded at their book value in accordance with GAAP. Book value of the consideration provided by our general partner and its affiliates, as of December 31, 2009, equals parent net investment, which was $449.4 million and includes approximately $16.6 million related to the intercompany indebtedness not repaid from the net proceeds of this offering and related borrowings under our new credit facility that will be extinguished and treated as a capital contribution and part of PAA s investment in us.

(3) Assumes the underwriters option to purchase additional common units is not exercised.

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OUR CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with Assumptions and Considerations below, which includes the factors and assumptions upon which we base our cash distribution policy. In addition, please read Forward-Looking Statements and Risk Factors for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business. For additional information regarding our historical operating results, you should refer to our historical consolidated financial statements, and the notes thereto, included elsewhere in this prospectus.

General

Rationale for Our Cash Distribution Policy. Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a fundamental judgment that our unitholders generally will be better served by our distributing rather than retaining our available cash. Basically, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except to distribute available cash as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

Our cash distribution policy is subject to restrictions on distributions under our new credit facility and other debt agreements entered into in the future may have similar restrictions. Our new credit facility contains material financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions under our credit facility, we will be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources New Credit Facility.

Our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those cash reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders. Our partnership agreement provides that in order for a determination by our general partner to be made in good faith, our general partner must subjectively believe that the determination is (i) with respect to matters involving us, in, or not opposed to, the best interests of our partnership and (ii) with respect to matters involving the relative rights and privileges of holders of our equity interests, consistent with the intent of the provisions of our partnership agreement.

Although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions contained therein that require us to make cash distributions, may be amended. Our partnership agreement can generally be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by PAA). At the closing of this offering, and assuming no exercise of the underwriters option to purchase additional common units, PAA will own our general partner and an aggregate of approximately 62.9% of our total outstanding common units.

Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets.

We may lack sufficient cash to pay distributions to our unitholders due to revenue shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expense, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar for dollar to the extent such uses of cash increase. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions Distributions of Available Cash.

If and to the extent our distributable cash flow materially declines, we may elect to reduce our quarterly distribution in order to service or repay our debt or fund expansion capital expenditures.

Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations.

Our Ability to Grow is Dependent on Our Ability to Access External Expansion Capital. Our partnership agreement requires us to distribute all of our available cash to our unitholders. As a result, we expect that we 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. To the extent we are unable to access such external sources to finance our growth, our cash distribution policy could significantly impair our ability to grow. In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement 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 Minimum Quarterly Distribution

Upon completion of this offering, the board of directors of our general partner will establish an initial minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit per complete quarter, or $1.35 per common unit and Series A subordinated unit per year, to be paid no later than 45 days after the end of each fiscal quarter beginning with the quarter ending June 30, 2010. This equates to an aggregate cash distribution of $15.7 million per quarter, or $62.7 million per year, based on the number of common units, Series A subordinated units and the 2.0% general partner interest to be outstanding immediately after the completion of this offering. Our ability to make cash distributions at the minimum quarterly distribution rate pursuant to this policy will be subject to the factors described above under the caption General Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy.

If the underwriters do not exercise their option to purchase additional common units, we will issue 1,758,000 common units to PAA at the expiration of the option period. If and to the extent the underwriters exercise their option to purchase additional common units, the number of units purchased by the underwriters pursuant to such exercise will be issued to the public and the remainder, if any, will be issued to PAA. Accordingly, the exercise of the underwriters option will not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all units. Please read Underwriting.

As of the date of this offering, our general partner will be entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner s initial 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its initial 2.0% general partner interest.

The table below sets forth the number of outstanding common units and Series A subordinated units upon the closing of this offering, assuming the underwriters do not exercise their option to purchase additional common units, and the aggregate distribution amounts payable on such units and the 2.0% general partner interest during the year following the closing of this offering at our minimum quarterly distribution rate of $0.3375 per common unit and Series A subordinated unit per quarter ($1.35 per common unit and Series A subordinated unit on an annualized basis).

		Minimum Quarterly Distributions	
	Number of Units	One Quarter	Annualized
Publicly held common units	11,720,000	$ 3,955,500	$ 15,822,000
Common units held by PAA	19,864,529	6,704,279	26,817,114
Series A subordinated units held by PAA	13,934,351	4,702,843	18,811,374
2.0% general partner interest	N/A	313,523	1,254,092
Total	45,518,880	$ 15,676,145	$ 62,704,580

We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about the 10th day prior to such payment date. If the distribution date does not fall on a business day, we will make the distribution on the business day immediately preceding the indicated distribution date. We will adjust the quarterly distribution for the period from the closing of this offering through June 30, 2010 based on the actual length of the period.

Series A Subordinated Units

PAA will initially own all of our Series A subordinated units. The principal difference between our common units and Series A subordinated units is that in any quarter during the subordination period, holders of the Series A subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Series A subordinated units will not accrue arrearages.

At any time on or after June 30, 2013, the subordination period will end on the first business day following the quarter in respect of which we have, for each of three consecutive, non-overlapping four quarter periods (i) generated from distributable cash flow at least $1.35 (the minimum quarterly distribution on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner s 2.0% interest and (ii) paid from available cash at least $1.35 on all outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distribution on our general partner s 2.0% interest. Additionally, at any time on or after June 30, 2011, if we have, for a period of four consecutive quarters (i) generated from distributable cash flow at least $0.5063 per quarter (150% of the minimum quarterly distribution, which is approximately $2.03 on an annualized basis) on the weighted average number of outstanding common units and Series A subordinated units, plus the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights and (ii) paid from available cash at least $0.5063 per quarter (150% of the minimum quarterly distribution, which is approximately $2.03 on an annualized basis) on all outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distribution on our general partner s 2.0% interest and the related distributions on the incentive distribution rights, the subordination period will end. When the subordination period ends, all of the Series A subordinated units will convert into an equal number of common units. Please read the Provisions of Our Partnership Agreement Relating to Cash Distributions

Subordination Period.

To the extent we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess available cash to pay any distribution arrearages on common units related to prior quarters before any cash distribution is made to holders of Series A subordinated units. Please read Provisions of Our Partnership Agreement Relating to Cash Distributions Subordination Period.

Distributable cash flow will be determined by our general partner and is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received.

Series B Subordinated Units

The Series B subordinated units that will be outstanding upon the consummation of this offering are not entitled to cash distributions unless and until they convert to Series A subordinated units or common units. The Series B subordinated units are designed to compensate PAA for prior capital expenditures made by it to expand the working gas storage capacity at Pine Prairie and the future financial contribution expected to result from such investment. We currently do not expect any of the Series B subordinated units to convert to Series A subordinated units or common units before June 30, 2011. As a result, we would not expect any Series B subordinated units to receive any distributions for the twelve-month period ending June 30, 2011. We may, however, make acquisitions or take other actions that could cause Series B subordinated units to convert to Series A subordinated units during this period. In order for Series B Subordinated units to convert to Series A subordinated units, the following financial and operating conditions must be satisfied:

4,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.36 per unit (representing an annualized distribution of \$1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) we make a quarterly distribution of available cash of at least \$0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights;

3,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least \$0.3825 per unit (representing an annualized distribution of \$1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) we make a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

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3,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) we make a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights.

Our general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period on an as-converted basis. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above operational and financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit each quarter for the twelve months ending June 30, 2011. In those sections, we present the following two tables:

Unaudited Pro Forma Available Cash from Distributable Cash Flow, in which we present the amount of available cash we would have had from distributable cash flow on a pro forma basis for our year ended December 31, 2009, as adjusted to give pro forma effect to the offering and the formation transactions as if the offering and such transactions had occurred on January 1, 2009; and

Statement of Minimum Estimated Available Cash from Distributable Cash Flow, in which we demonstrate our anticipated ability to generate the minimum estimated available cash from distributable cash flow necessary for us to pay the minimum quarterly distribution on all common units and Series A subordinated units for the twelve months ending June 30, 2011.

Unaudited Pro Forma Available Cash from Distributable Cash Flow for the Year Ended December 31, 2009

If we had completed the transactions contemplated in this prospectus on January 1, 2009, pro forma available cash from distributable cash flow generated for the year ended December 31, 2009 would have been approximately

$35.2 million and would have enabled us to make an annualized distribution of approximately $1.11 (approximately 82.6% of the minimum quarterly distribution) on each of the common units and no distribution on the Series A subordinated units. These distributions are significantly less than the amounts that would have been required to pay the minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit per quarter ($1.35 per common unit and Series A subordinated unit on an annualized basis).

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Unaudited pro forma available cash from distributable cash flow also includes incremental general and administrative expenses we will incur as a result of being a publicly traded limited partnership, including costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, Sarbanes-Oxley compliance, New York Stock Exchange listing, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation. We expect our incremental general and administrative expenses associated with being a publicly traded limited partnership to total approximately $2.6 million per year. Such incremental general and administrative expenses are not reflected in our historical consolidated financial statements or our unaudited pro forma condensed combined financial statements.

The following table illustrates, on a pro forma basis, for the year ended December 31, 2009, the amount of our available cash from distributable cash flow, assuming that this offering had been consummated at the beginning of such period. Each of the pro forma adjustments presented below is explained in the footnotes to such adjustments.

We based the pro forma adjustments upon currently available information and specific estimates and assumptions. The pro forma amounts below do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. In addition, cash available to pay distributions is primarily a cash accounting concept, while our historical consolidated financial statements have been prepared on an accrual basis. As a result, you should view the amount of pro forma available cash from distributable cash flow only as a general indication of the amount of available cash from distributable cash flow that we might have generated had we been formed in earlier periods.

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PAA Natural Gas Storage, L.P.

Unaudited Pro Forma Available Cash from Distributable Cash Flow

	Year Ended December 31, 2009 (in millions, except per unit data)
Pro forma net income[(1)]	**$ 24.0**
Add:	
Interest expense, net of capitalized interest[(1)(2)]	0.8
Income tax expense[(1)(2)(3)]	0.5
Depreciation, depletion and amortization[(1)(2)(4)]	12.2
Equity compensation expense[(1)(2)(5)]	1.8
Mark-to-market on open derivative positions[(1)(2)(6)]	0.4
Pro forma Adjusted EBITDA[(7)]	**$ 39.7**
Adjusted for:	
Incremental general and administrative expense of being a public company[(8)]	(2.6)
Pro forma net cash paid for interest expense[(9)(10)]	(0.8)
Cash paid for equity compensation	(0.4)
Acquisition related cost[(11)]	
Expansion capital expenditures[(12)]	79.0
Borrowings to fund expansion capital expenditures[(12)]	(79.0)
Maintenance capital expenditures[(13)]	(0.7)
Pro forma available cash from distributable cash flow	**$ 35.2**
Pro forma cash distributions	
Distributions on publicly held common units[(14)]	$ 15.8
Distributions on common units held by PAA[(14)]	26.8
Distributions on Series A subordinated units held by PAA[(14)]	18.8
Distributions on 2.0% general partner interest held by PAA[(14)]	1.3
Total distributions	62.7
Excess/(Shortfall)	**$ (27.5)**
Percent of minimum quarterly distributions payable to common unitholders	**82.6%**
Percent of minimum quarterly distributions payable to Series A subordinated unitholders	**0%**
Interest coverage ratio[(15)]	49.6x
Leverage ratio[(15)]	5.0x

(1) Reflects our pro forma operating results for the year ended December 31, 2009, derived from our unaudited pro forma condensed combined financial statements included elsewhere in this prospectus. The pro forma

adjustments have been prepared as if the PAA Ownership Transaction, this offering and the anticipated borrowings under our credit facility had taken place on January 1, 2009.

(2) Reflects adjustments necessary to reconcile net income to pro forma Adjusted EBITDA.

(3) Reflects primarily Michigan state income tax.

(4) Reflects one year of amortization expense associated with approximately $2.4 million of debt issue costs which we incurred in connection with our new three-year revolving credit facility. In accordance with our accounting policies, we reflect amortization of debt issue costs as a component of depreciation, depletion and amortization expense.

(5) Represents expense associated with grants under PAA s long-term incentive plans to employees that are dedicated to our operations.

(6) Cash settlements of derivative activity are generally reflected in our distributable cash flow in the period during which settlement occurs. With respect to any particular derivative, to the extent there are any timing differences between cash settlements and associated amounts reflected as a component of net income for the period, we reflect such timing differences as a reconciling item between net income and distributable cash flow for the period. Cash settlements on open derivative positions at December 31, 2009 were not material for the year ended December 31, 2009.

(7) We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring. Because Adjusted EBITDA excludes some, but not all, items that affect net income and may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA has important limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Please see Summary Non-GAAP and Segment Financial Measures.

(8) Reflects an adjustment to our Adjusted EBITDA for an estimated incremental cash expense associated with being a publicly traded limited partnership, including costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, Sarbanes-Oxley compliance, New York Stock Exchange listing, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation.

(9) Cash paid for capitalized interest is treated as an expansion capital expenditure for purposes of our determination of distributable cash flow. On a pro forma basis, cash paid to settle capitalized interest during the year ended December 31, 2009 was approximately $7.5 million and is included as a component of Expansion capital expenditures.

(10) In connection with this offering, we entered into a new $400 million credit agreement under which we expect to incur approximately $200 million of borrowings upon the closing of this offering. The pro forma cash interest expense is based on $200 million of historical borrowings at an assumed rate based on a forecast of LIBOR rates during the period plus the margin and associated commitment fees under our new credit facility, net of capitalized interest, with the remainder of historical borrowings financed with equity proceeds from this offering.

(11) In our determination of distributable cash flow, we adjust net income to add back acquisition-related expenses associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned. Such expenses primarily include costs which are required to be expensed in accordance with applicable accounting guidance. We did not incur any such costs in the year ended December 31, 2009 that met the criteria for adjustment in our determination of distributable cash flow. During the year ended December 31, 2009, we did not incur any acquisition-related expenses other than those required to be expensed.

(12) Expansion capital expenditures are made to acquire additional assets to grow our business, to expand and upgrade our systems and facilities and to construct or acquire similar systems or facilities. During the year ended December 31, 2009 on a pro forma basis, we made expansion capital expenditures of approximately $79.0 million. Pro forma expansion capital expenditures of $79.0 million were determined by adjusting actual expansion capital expenditures for 2009 of $90.0 million to remove historical capitalized interest for 2009 of approximately $15.6 million and historical 2009 accrued expansion capital expenditures of approximately $2.9 million and reflect pro forma capitalized interest of approximately $7.5 million. Because we expect that in

the future expansion capital expenditures will primarily be funded through borrowings or the sale of debt or equity securities, we have assumed additional borrowings to offset our expansion capital expenditures for purposes of calculating our pro forma cash available for distribution.

(13) Maintenance capital expenditures are cash capital expenditures made for the purpose of maintaining or replacing the operating capacity, service capability and/or functionality of our existing assets. Examples of maintenance capital expenditures include capital expenditures associated with maintaining the storage capacity of our facilities as well as ongoing maintenance or replacement costs for the various injection,

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withdrawal and related equipment costs associated with those facilities, to replace expected reductions in our storage, injection or withdrawal capacities (which we refer to as operating capacity).

(14) The table below sets forth the number of outstanding common units and Series A subordinated units upon the closing of this offering and the expiration of the option period, and the per common unit and Series A subordinated unit and aggregate distribution amounts payable on our common units and Series A subordinated units, as well as the aggregate distribution amount payable on the 2.0% general partner interest for four quarters at our initial distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis).

	Number of Units	Distributions for Four Quarters	
		Per Unit	Aggregate
Pro forma distributions on publicly-held common units	11,720,000	$ 1.35	$ 15,822,000
Pro forma distributions on common units held by PAA[(a)]	19,864,529	$ 1.35	26,817,114
Pro forma distributions on Series A subordinated units held by PAA	13,934,351	$ 1.35	18,811,374
Pro forma distributions on 2.0% general partner interest			1,254,092
Total	45,518,880	$ 1.35	$ 62,704,580

(a) The number of common units held by PAA includes 1,758,000 common units subject to the underwriters option to purchase additional common units. If and to the extent this option is exercised, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public instead of PAA and the remainder, if any, will be issued to PAA at the expiration of the underwriters option period.

The Series B subordinated units that will be outstanding upon the consummation of this offering are not entitled to cash distributions unless and until they convert to Series A subordinated units or common units. Please read Series B Subordinated Units above.

(15) The interest coverage ratio and leverage ratio are based on the pro forma results for the period ended December 31, 2009. At December 31, 2009, we were not subject to any financial covenants under the funding arrangement and note payable to PAA. However, our new credit agreement contains financial covenants requiring us to maintain:

a minimum consolidated interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest charges, which is net of capitalized interest, in each case as such terms are defined in our credit agreement) of not less than 3.0 to 1.0, determined as of the last day of each quarter for the four-quarter period ending on the date of determination; and

a maximum consolidated leverage ratio (the ratio of our consolidated funded indebtedness to our consolidated EBITDA, in each case as such terms are defined in our credit agreement) of not more than 4.75 to 1.0 (or, on a temporary basis for not more than three consecutive quarters following the consummation of certain acquisitions, not more than 5.5 to 1.0).

Minimum Estimated Available Cash from Distributable Cash Flow for the Twelve Months Ending June 30, 2011

In order to fund distributions to our unitholders at our initial minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit for the twelve months ending June 30, 2011, our minimum estimated available cash from distributable cash flow for the twelve months ending June 30, 2011 must be at least $62.7 million. This minimum estimated available cash from distributable cash flow should not be viewed as management s projection of the actual amount of available cash from distributable cash flow that we will generate during the twelve month period ending June 30, 2011. We believe that we will be able to generate this minimum estimated available cash from distributable cash flow based on the assumptions discussed in Assumptions and Considerations below.

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We can give you no assurance, however, that we will generate the minimum estimated available cash from distributable cash flow. There will likely be differences between our minimum estimated available cash from distributable cash flow and our actual results and those differences could be material. If we fail to generate the minimum estimated available cash from distributable cash flow, we may not be able to pay the minimum quarterly distribution on our common units.

Management has prepared the minimum estimated available cash from distributable cash flow and related assumptions set forth below to substantiate our belief that we will have sufficient available cash from distributable cash flow to pay the minimum quarterly distribution to all our common unitholders and Series A unitholders for the twelve months ending June 30, 2011. This forecast is a forward-looking statement and should be read together with the historical financial statements and the accompanying notes included elsewhere in this prospectus and Management s Discussion and Analysis of Financial Condition and Results of Operations. The accompanying prospective financial information was not prepared with a view toward complying with the published guidelines of the Securities and Exchange Commission or the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management s knowledge and belief, the assumptions on which we base our belief that we can generate the minimum estimated available cash from distributable cash flow necessary for us to pay the minimum quarterly distribution to all common unitholders and Series A subordinated unitholders for the twelve months ending June 30, 2011. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

The prospective financial information included in this registration statement has been prepared by, and is the responsibility of, our management. PricewaterhouseCoopers LLP has neither compiled nor performed any procedures with respect to the accompanying prospective financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP report included in this registration statement relates to our historical financial information. It does not extend to the prospective financial information and should not be read to do so.

When considering our financial forecast, you should keep in mind the risk factors and other cautionary statements under Risk Factors. Any of the risks discussed in this prospectus, to the extent they are realized, could cause our actual results of operations to vary significantly from those which would enable us to generate the minimum estimated available cash from distributable cash flow.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

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PAA Natural Gas Storage, L.P.
Unaudited Minimum Estimated Available Cash from Distributable Cash Flow

	Twelve Months Ending June 30, 2011 (in millions, except per unit data)
Firm storage services	$ 103.5
Hub services	16.0
Other	2.9
Total revenue	122.4
Storage related costs	17.7
Operating costs (except those shown below)	9.2
Fuel expense	10.8
General and administrative expenses	13.7
Depreciation, depletion and amortization[1]	15.1
Total costs and expenses	66.5
Operating income	55.9
Interest expense, net of capitalized interest	4.5
Income tax expense[2]	
Net income	**$ 51.4**
Add:	
Depreciation, depletion and amortization	15.1
Interest expense, net of capitalized interest	4.5
Equity compensation expense[3]	1.6
Income tax expense[2]	
Adjusted EBITDA[4]	72.6
Less:	
Equity compensation expense cash[3]	0.6
Interest expense, net of capitalized interest[5]	4.5
Maintenance capital expenditures	0.4
Expansion capital expenditures	80.0
Income tax expense cash[2]	
Mark to market on open derivatives positions[6]	
Add:	
Borrowings to fund expansion capital expenditures	80.0
Acquisition costs[7]	
Estimated distributable cash flow	67.1
Less:	
Cash reserves	4.4
Minimum estimated available cash from distributable cash flow	**$ 62.7**

Per unit minimum annual distribution	$ 1.35
Annual distributions to:	
Publicly held common units	$ 15.8
Common units held by PAA	26.8
Series A subordinated units held by PAA	18.8
2.0% general partner interest held by PAA	1.3
Total minimum annual cash distributions	$ 62.7
Interest coverage ratio(8)	16.1x
Leverage ratio(8)	3.9x

(1) Includes approximately $0.8 million associated with amortization of debt issue costs on our new revolving credit facility.

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(2) Michigan state income tax is an apportionment tax and, based on the size of our operations at Pine Prairie, such amounts are expected to be immaterial in the forecast period.

(3) Reflects our estimate of expense associated with grants under our and PAA s long-term incentive plans.

(4) We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring. Because Adjusted EBITDA excludes some, but not all, items that affect net income and may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. Adjusted EBITDA has important limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. Please see Summary Summary Historical Financial and Operating Data Non-GAAP and Segment Financial Measures.

(5) Cash paid for capitalized interest is treated as an expansion capital expenditure for purposes of our determination of distributable cash flow. Estimated cash paid to settle capitalized interest during the twelve months ended June 30, 2011 is approximately $6.0 million and is included as a component of Expansion capital expenditures.

(6) For purposes of estimated available cash from distributable cash flow for the period, we did not project the potential impact of any derivative financial instruments to our forecasted operating results for the period as we do not believe such activity is reasonably estimable.

(7) In our determination of distributable cash flow, we adjust net income to add back acquisition-related expenses associated with (i) successful acquisitions or (ii) any other potential acquisitions that have not been abandoned. Such expenses primarily include costs which are required to be expensed in accordance with applicable accounting guidelines. We do not project any such costs in the twelve months ending June 30, 2011 that meet the criteria for adjustment in our determination of distributable cash flow. During the twelve months ending June 30, 2011, we do not project any acquisition-related expenses other than those required to be expensed.

(8) Our credit agreement contains certain customary covenants limiting our ability to (i) make distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists or would result therefrom, (ii) incur additional indebtedness, (iii) grant or permit to exist liens or enter into certain restricted contracts, (iv) engage in transactions with affiliates, (v) make any material change to the nature of our business, (vi) make a disposition of all or substantially all of our assets or (vii) enter into a merger, consolidate, liquidate, wind up or dissolve.

In addition, our credit agreement contains financial covenants requiring us to maintain:

a minimum consolidated interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest charges, which is net of capitalized interest, in each case as such terms are defined in our credit agreement) of not less than 3.0 to 1.0, determined as of the last day of each quarter for the four-quarter period ending on the date of determination; and

a maximum consolidated leverage ratio (the ratio of our consolidated funded indebtedness to our consolidated EBITDA, in each case as such terms are defined in our credit agreement) of not more than 4.75 to 1.0 (or, on a temporary basis for not more than three consecutive quarters following the consummation of certain acquisitions, not more than 5.5 to 1.0).

If an event of default exists under our credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies.

Assumptions and Considerations

We believe our minimum estimated available cash from distributable cash flow for the twelve months ending June 30, 2011 will not be less than $62.7 million. This amount of estimated minimum available cash from distributable cash flow is approximately $27.5 million, or approximately 78.1%, more than the unaudited pro forma available cash from distributable cash flow for the year ended December 31, 2009. The December 31, 2009 financial information used in the pro forma table is derived by combining the Predecessor

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period ended September 2, 2009 with the Successor period ended December 31, 2009 from our historical financial statements. This significant increase in available cash from distributable cash flow is primarily attributable to additional storage capacity at Pine Prairie as described in detail below. Our estimates do not assume any incremental revenue, expenses or other costs associated with potential acquisitions, but do include appropriate start-up levels of incremental net margin contributions associated with our expected establishment of a commercial marketing group during 2010. We believe that the estimates, assumptions and considerations incorporated into the minimum estimated available cash from distributable cash flow are reasonable, and include the following:

Operating Revenue

We estimate that we will generate $122 million in revenues for the twelve months ending June 30, 2011, as follows:

Revenues from Firm Storage. We estimate that approximately 85%, or approximately $104 million, of our total revenue will be generated from firm storage services. This compares to approximately 92%, or approximately $67 million, of our total revenues that were generated from firm storage revenues during the 12 month period ended December 31, 2009. Furthermore, we have assumed that:

(i) Approximately 75% of our total revenue will be generated from firm storage services provided under contracts in existence as of April 1, 2010, which cover approximately 52 Bcf of our approximate 54.5 Bcf of total owned and leased working gas capacity as of April 1, 2010, including the 10 Bcf of additional capacity we expect to place into service during the second quarter of 2010; and

(ii) Approximately 10% of our total revenue will be generated from firm storage services provided under contracts entered into after April 1, 2010 that will cover (a) the remaining 2.5 Bcf of our approximate 54.5 Bcf of total owned and leased working gas capacity as of April 1, 2010, (b) the 8 Bcf of additional working gas capacity we expect to place into service during the second quarter of 2011 and (c) renewals of existing firm storage contracts covering approximately 11 Bcf of working gas capacity at our Bluewater facility, the terms of which expire on March 31, 2011. With respect to such contracts to be entered into after April 1, 2010, we have assumed we will earn storage rates on such capacity that are consistent with our rates for new contracts entered into over the last 18 months.

Revenues from Hub Services. We estimate that approximately 13%, or approximately $16 million, of our total revenues will be generated from hub services, which includes non-seasonal parks and loans, wheeling and balancing services and interruptible storage services. This compares to approximately 7%, or approximately $5 million, of revenues from hub services generated during the twelve-month period ended December 31, 2009. Our estimate with respect to the level of hub services revenues for the forecast period incorporates assumptions with respect to increased natural gas flows and related hub service opportunities at Pine Prairie associated with (i) an approximate 115% increase relative to our weighted average storage capacity during 2009, (ii) increased flexibility provided both by an approximate 50% increase in compression capacity and an approximate 115% increase in base gas relative to the 2009 period, (iii) a continuation of volatility related to market conditions and weather consistent with those experienced over the last five years and (iv) the establishment of a commercial marketing group during 2010.

Other Revenues. We estimate that approximately 2%, or approximately $2.9 million, of our total revenues will be generated from the sale of crude oil and other liquid hydrocarbons produced in conjunction with the operation of our Bluewater facility. This compares to approximately 1%, or approximately $0.9 million, of other revenues generated during the twelve-month period ended December 31, 2009. Fuel related revenue for both firm and hub services is based on an average natural gas price of $5.32 per mcf, which approximates the average price quoted on NYMEX in late March 2010 for the twelve months ended June 30, 2011. No gains or losses were assumed with respect to the sale of excess fuel collections.

Incremental storage capacity additions related to our ongoing expansion at Pine Prairie constitute the primary driver for the approximate $48 million increase in estimated firm storage and hub services revenues, as:

our second cavern began generating revenue on April 1, 2009, and thus revenue associated with the added 9 Bcf of incremental storage capacity is only included for nine months of the twelve-month period ended December 31, 2009;

our third cavern began generating revenue on April 1, 2010 and will be placed into full service during the second quarter of 2010, providing an expected 10 Bcf of incremental storage capacity for the entire twelve-month period ending June 30, 2011; and

our fourth cavern is expected to begin generating revenue on April 1, 2011 and be placed into full service during the second quarter of 2011, providing an expected 8 Bcf of incremental storage capacity for the final three months of the twelve-month period ending June 30, 2011.

As a result of these expansions, our weighted average working gas capacity at Pine Prairie will increase from approximately 12 Bcf for the twelve-month period ended December 31, 2009 to approximately 26 Bcf for the twelve-month period ending June 30, 2011.

Our Expenses

We estimate that operating, fuel and leased storage costs and transportation expenses will be $37.7 million for the twelve months ending June 30, 2011, as compared to $26.3 million for the year ended December 31, 2009. This increase is generally attributable to costs associated with the incremental storage capacity related to the ongoing expansion at our Pine Prairie facility. We do not expect our operating expenses to increase proportionately with our capacity additions, both because these additions do not require significant additions of operating employees and because the revenues associated with the additions have the benefit of the tax exemption we have obtained at Pine Prairie. See Business Title to Properties and Rights-of-way.

We estimate that our total general and administrative expense will be $13.7 million for the twelve months ended June 30, 2011, as compared to $7.6 million for the year ended December 31, 2009. This projected increase includes additional personnel and related costs associated with our preparation to become a publicly traded limited partnership, an increased level of acquisition activity and approximately $2.6 million of incremental external costs we expect to begin incurring upon becoming a publicly traded limited partnership. These general and administrative expenses include corporate general and administrative expense to be allocated from PAA. Such general and administrative expense reflects twelve months of increased allocations from PAA consistent with historical allocations subsequent to the PAA Ownership Transaction. The joint venture agreement in place with Vulcan Capital prior to the PAA Ownership Transaction did not permit PAA to charge us for executive officer expenses.

We have not included any amounts related to the Michigan state income tax applicable to our operations in the twelve months ending June 30, 2011. This tax is an apportionment tax and, because of the size of our operations at Pine Prairie, is expected to be immaterial in the forecast period.

Our Capital Expenditures

We estimate that our maintenance capital expenditures will be approximately $0.4 million for the twelve months ending June 30, 2011, as compared to $0.7 million for the year ended December 31, 2009. Our maintenance capital expenditures are not significant in the forecast period because our storage facilities and related equipment are relatively new. We would expect maintenance capital expenditures to increase periodically as we undertake scheduled maintenance on our caverns and related equipment. While these periodic costs may increase our maintenance capital expenditures from time to time, we do not expect these increases to materially impact our operating results or distributable cash flow.

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We estimate that our expansion capital expenditures, which include the purchase of base gas and capitalized interest, will be approximately $80 million for the twelve months ending June 30, 2011, as compared to $90 million for the year ended December 31, 2009. The substantial majority of this capital is attributable to the capacity additions at our Pine Prairie facility.

Our Financing

We estimate that at the closing of this offering we will borrow $200 million in revolving debt under our new $400 million credit facility. We estimate that the borrowings will bear interest at a weighted average rate of 4%. This rate is based on a forecast of LIBOR rates during the period plus the margin and associated commitment fees under our new credit facility. In addition, we have assumed that we will fund our expansion capital expenditures for the twelve months ended June 30, 2011 by borrowing an additional $80 million under our new credit facility.

Our aggregate interest expense is forecast to be $4.5 million, net of $6.0 million in capitalized interest.

Our Regulatory, Industry and Economic Factors

Our estimate incorporates assumptions that (i) there will not be any new federal, state or local regulations or any new interpretations of existing regulations, that would materially impact our or our customers operations, and (ii) there will not be any major adverse economic changes in the portions of the energy industry in which we operate, or in general economic conditions, that would be materially adverse to our business during the twelve months ending June 30, 2011.

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PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

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

Distributions of Available Cash

General. Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ending June 30, 2010, we distribute all of our available cash to unitholders of record on the applicable record date. We will adjust the minimum quarterly distribution for the period from the closing of the offering through June 30, 2010.

Definition of Available Cash. Available cash, for any quarter, consists of all cash on hand at the end of that quarter:

less, the amount of cash reserves established by our general partner to:

provide for the proper conduct of our business;

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to our unitholders for any one or more of the next four quarters;

plus, if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter resulting from borrowings, including working capital borrowings, made after the end of the quarter.

Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners. In addition, all such borrowings are required to be reduced to zero within twelve months of incurrence for an economically meaningful period of time from sources other than working capital borrowings.

Intent to Distribute the Minimum Quarterly Distribution. We intend to distribute to the holders of common units and Series A subordinated units on a quarterly basis at least the minimum quarterly distribution of $0.3375 per unit, or $1.35 per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

General Partner Interest and Incentive Distribution Rights. Initially, our general partner will be entitled to 2.0% of all quarterly distributions that we make after inception and prior to our liquidation. The general partner interest will be represented by a 2.0% general partner interest. The 2.0% general partner interest is not deemed outstanding for purposes of voting and such interest represents a non-voting general partner interest. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner s initial 2.0% interest in our distributions may be reduced if we issue additional limited partner units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from distributable cash flow in excess of approximately $2.03 per common unit and Series A subordinated unit per quarter. The maximum distribution of 50.0% includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general partner interest at 2.0%. The maximum distribution of 50.0% does not include any distributions that our general partner may receive on limited partner units that it owns.

Distributable Cash Flow and Capital Surplus

General. All cash distributed to unitholders will be characterized as either distributable cash flow or capital surplus. Our partnership agreement requires that we distribute available cash from distributable cash flow differently than available cash from capital surplus.

Distributable Cash Flow. Distributable cash flow will be determined by our general partner and is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received.

As described above, distributable cash flow does not reflect actual cash on hand that is available for distribution to our unitholders. Our definition of distributable cash flow is generally designed and intended to adjust net income (as determined in accordance with generally accepted accounting principles) for items that do not impact the amount of available cash we have available for distribution to our unitholders but may be required to be reflected in net income by applicable accounting rules and regulations.

Characterization of Cash Distributions. Our partnership agreement requires that we treat all available cash distributed as coming from distributable cash flow until the sum of all available cash distributed since the closing of this offering equals the distributable cash flow as of the most recent date of determination of available cash. Our partnership agreement requires that we treat any amount distributed in excess of distributable cash flow, regardless of its source, as capital surplus. However, our partnership agreement includes a provision that will enable us, if we choose, to distribute up to $40 million of cash we receive in the future from sources other than distributable cash flow, such as asset sales, issuances of securities and borrowings, without being required to classify such distribution as a distribution from capital surplus under our partnership agreement. We do not anticipate that we will make any distributions from capital surplus.

Maintenance Capital Expenditures

For purposes of determining distributable cash flow, maintenance capital expenditures are cash capital expenditures made for the purpose of maintaining or replacing the operating capacity, service capability, and/or functionality of our existing assets. Examples of maintenance capital expenditures include capital expenditures associated with maintaining the storage capacity of our facilities as well as ongoing maintenance or replacement costs for the various injection, withdrawal and related equipment associated with those facilities, and capital expenditures to replace expected reductions in our storage, injection or withdrawal capacities (which we refer to as operating capacity).

Subordination Period

General. Our partnership agreement provides that, during the subordination period (which we define below), the common units will have the right to receive distributions of available cash from distributable cash flow each quarter in an amount equal to $0.3375 per common unit, which amount is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from distributable cash flow may be made on the Series A subordinated units. These Series A subordinated units are deemed subordinated because for a period of time, referred to as the subordination period, the Series A subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the Series A subordinated units. The practical effect of the Series A subordinated units is to increase the likelihood that during the subordination period there will be available cash to be distributed on the common units. The Series B subordinated units will not be entitled to receive any distributions until they are converted to either Series A subordinated units or common units, at which time they will be treated as other Series A subordinated units or common units, as applicable, are treated.

Series A Subordinated Units and Subordination Period. PAA will initially own all of our Series A subordinated units. At any time on or after June 30, 2013, the subordination period will end on the first business day following the quarter in respect of which each of the following tests are met:

- distributions of available cash from distributable cash flow on all outstanding common units, Series A subordinated units and the general partner interest equaled or exceeded the minimum quarterly distribution for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the distributable cash flow generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of the minimum quarterly distributions on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distributions on our general partner s 2.0% interest during those periods; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

Early Termination of Subordination Period. Notwithstanding the foregoing, at any time on or after June 30, 2011, the subordination period will end on the first business day following the quarter in respect of which each of the following tests are met:

- distributions of available cash from distributable cash flow equaled or exceeded approximately $0.5063 per quarter (150% of the minimum quarterly distribution, which is approximately $2.03 on an annualized basis) on all outstanding common units and Series A subordinated units, plus the corresponding distribution on our general partner s 2.0% interest and the related distributions on the incentive distribution rights for each calendar quarter in the immediately preceding four-quarter period;

- the distributable cash flow generated during each calendar quarter in the immediately preceding four-quarter period equaled or exceeded the sum of approximately $0.5063 (150% of the minimum quarterly distribution) on the weighted average number of outstanding common units and Series A subordinated units on a fully diluted basis, plus the corresponding distribution on our general partner s 2.0% interest during that period and the related distributions on the incentive distribution rights; and

- there are no arrearages in payment of the minimum quarterly distributions on the common units.

Expiration of the Subordination Period. When the subordination period ends, each outstanding Series A subordinated unit will convert into one common unit and will then participate pro rata with the other common units in distributions of available cash. Any Series B subordinated units that become eligible for conversion after the end of the subordination period will convert to common units an a one-for-one basis and will then participate pro rata with the other common units in distributions of available cash. In addition, if the unitholders remove our general partner other than for cause and no units held by our general partner and its affiliates are voted in favor of such removal:

- the subordination period will end and each Series A subordinated unit will immediately convert into one common unit;

each Series B subordinated unit will immediately convert into one common unit;

any existing arrearages in payment of the minimum quarterly distribution on the common units will be extinguished; and

our general partner will have the right to convert its general partner interest and its incentive distribution rights into common units or to receive cash in exchange for those interests.

Series B Subordinated Units. PAA will initially own all of the Series B subordinated units. The Series B subordinated units will not be entitled to participate in our quarterly distributions until they convert into Series A subordinated units or common units.

The Series B subordinated units are designed to compensate PAA for prior capital expenditures made by it to expand the working gas storage capacity at Pine Prairie and the future financial contribution expected to result from such investment. As of the closing of this offering, we expect to have approximately 24 Bcf of working gas storage capacity at Pine Prairie, including approximately 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

4,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) we make a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights;

3,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) we make a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all of outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights; and

3,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) we make a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on our general partner s 2.0% interest and the related distributions on the incentive distribution rights.

Our general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period on an as-converted basis. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

Following conversion of any Series B subordinated units into Series A subordinated units, such converted Series B subordinated units will further convert into common units (together with any other outstanding Series A subordinated units) to the extent that the tests for conversion of the Series A subordinated units are satisfied. In determining whether such conversion tests have been satisfied, the Series B subordinated units that have converted into Series A subordinated units will be treated as Series A subordinated units from and after the date of their conversion into Series A subordinated units.

If at the time the above financial tests are satisfied, the subordination period has already ended and all outstanding Series A subordinated units have converted into common units, the Series B subordinated units will instead convert directly into common units on a one-for-one basis and participate in the quarterly distribution payable to common units.

Distributions of Available Cash from Distributable Cash Flow During the Subordination Period

Our partnership agreement requires that we make distributions of available cash from distributable cash flow for any quarter during the subordination period in the following manner:

first, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to the minimum quarterly distribution for that quarter;

second, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding common unit an amount equal to any arrearages in payment of the minimum quarterly distribution on the common units for any prior quarters during the subordination period;

third, 98.0% to the Series A subordinated unitholders, pro rata, and 2.0% to our general partner, until we distribute for each Series A subordinated unit an amount equal to the minimum quarterly distribution for that quarter; and

thereafter, in the manner described in General Partner Interest and Incentive Distribution Rights below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash From Distributable Cash Flow After the Subordination Period

Our partnership agreement requires that we make distributions of available cash from distributable cash flow for any quarter after the subordination period in the following manner:

first, 98.0% to all common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and

thereafter, in the manner described in General Partner Interest and Incentive Distribution Rights below.

The preceding discussion is based on the assumptions that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our general partner initially will be entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest if we issue additional units. Our general partner s 2.0% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest. Our general partner will be entitled to make a capital contribution in order to maintain its 2.0% general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from distributable cash flow after the minimum quarterly distribution and the target distribution levels have been achieved. Our general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that our general partner maintains its 2.0% general partner interest, that there are no arrearages on common units and that our general partner continues to own the incentive distribution rights.

If for any quarter:

we have distributed available cash from distributable cash flow to the common unitholders and Series A subordinated unitholders in an amount equal to the minimum quarterly distribution; and

we have distributed available cash from distributable cash flow on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from distributable cash flow for that quarter among the unitholders and the general partner in the following manner:

first, 85.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 15.0% to our general partner, until each such unitholder receives a total of approximately $0.37125 per unit for that quarter (the first target distribution);

second, 75.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 25.0% to our general partner, until each such unitholder receives a total of approximately $0.50625 per unit for that quarter (the second target distribution); and

thereafter, 50.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 50.0% to our general partner.

Percentage Allocations of Available Cash From Distributable Cash Flow

The following table illustrates the percentage allocations of available cash from distributable cash flow between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth under Marginal Percentage Interest in Distributions are the percentage interests of our general partner and the unitholders in any available cash from distributable cash flow we distribute up to and including the corresponding amount in the column Total Quarterly Distribution per Common Unit and Series A Subordinated Unit. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest, assume our general partner has contributed any additional capital to maintain its

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2.0% general partner interest and has not transferred its incentive distribution rights and there are no arrearages on common units.

	Total Quarterly Distribution per Common Unit and Series A Subordinated Unit	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$ 0.3375	98.0%	2.0%
First Target Distribution	above $ 0.3375 up to $0.37125	85.0%	15.0%
Second Target Distribution	above $ 0.37125 up to $0.50625	75.0%	25.0%
Thereafter	above $ 0.50625	50.0%	50.0%

General Partner s Right to Reset Incentive Distribution Levels

Our general partner, as the holder of our incentive distribution rights, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and to reset, at higher levels, the minimum quarterly distribution amount, and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. Our general partner s right to reset the minimum quarterly distribution amount, and the target distribution levels upon which the incentive distributions payable to our general partner are based, may be exercised, without approval of our unitholders or the conflicts committee of our general partner, at any time when there are no Series A subordinated units outstanding and we have made cash distributions to the holders of the incentive distribution rights at the highest level of incentive distribution for each of the prior four consecutive fiscal quarters. Our general partner will have the right to reset the minimum quarterly distribution whether or not any Series B subordinated units remain outstanding. The reset minimum quarterly distribution amount and target distribution levels will be higher than the minimum quarterly distribution amount and the target distribution levels prior to the reset such that our general partner will not receive any incentive distributions under the reset target distribution levels until cash distributions per common unit following this event increase as described below. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would otherwise not be sufficiently accretive to cash distributions per common unit, taking into account the existing levels of incentive distribution payments being made to our general partner.

In connection with the resetting of the minimum quarterly distribution amount and the target distribution levels and the corresponding relinquishment by our general partner of incentive distribution payments based on the target cash distributions prior to the reset, our general partner will be entitled to receive a number of newly issued common units based on a predetermined formula described below that takes into account the cash parity value of the average cash distributions related to the incentive distribution rights received by our general partner for the two quarters prior to the reset event as compared to the average cash distributions per common unit during this period. In addition, our general partner will be issued a general partner interest necessary to maintain our general partner s interest in us immediately prior to the reset election.

The number of common units that our general partner would be entitled to receive from us in connection with a resetting of the minimum quarterly distribution amount and the target distribution levels then in effect would be equal to the quotient determined by dividing (x) the average amount of cash distributions received by our general partner in respect of its incentive distribution rights during the two consecutive fiscal quarters ended immediately prior to the date of such reset election by (y) the average of the amount of cash distributed per common unit during each of these two quarters.

Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (which amount we refer to as the reset minimum quarterly distribution) and the target distribution levels will be reset to be correspondingly higher such that we would distribute all of our available cash from distributable cash flow for each quarter thereafter as follows:

- *first*, 98.0% to all common unitholders, pro rata, and 2.0% to our general partner, until each such unitholder receives an amount per unit equal to the reset minimum quarterly distribution for that quarter;
- *second*, 85.0% to all common unitholders, pro rata, and 15.0% to our general partner, until each such unitholder receives an amount per unit equal to 110% of the reset minimum quarterly distribution for the quarter;
- *third*, 75.0% to all common unitholders, pro rata, and 25.0% to our general partner, until each such unitholder receives an amount per unit equal to 150% of the reset minimum quarterly distribution for the quarter; and
- *thereafter*, 50.0% to all common unitholders, pro rata, and 50.0% to our general partner.

The following table illustrates the percentage allocation of available cash from distributable cash flow between the unitholders and our general partner at various cash distribution levels (i) pursuant to the cash distribution provisions of our partnership agreement in effect at the closing of this offering, as well as (ii) following a hypothetical reset of the minimum quarterly distribution and target distribution levels based on the assumption that the average quarterly cash distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.60.

	Quarterly Distribution per Common Unit Prior to Reset	Marginal Percentage Interest in Distribution		Quarterly Distribution per Common Unit Following Hypothetical Reset
		Unitholders	General Partner	
Minimum Quarterly Distribution	$0.3375	98.0%	2.0%	$0.60(1)
First Target Distribution	above $0.3375 up to $0.37125	85.0%	15.0%	above $0.60(1) up to $0.66(2)
Second Target Distribution	above $0.37125 up to $0.50625	75.0%	25.0%	above $0.66(2) up to $0.90(3)
Thereafter	above $0.50625	50.0%	50.0%	above $0.90(3)

(1) This amount is equal to the hypothetical reset minimum quarterly distribution.

(2) This amount is 110% of the hypothetical reset minimum quarterly distribution.

(3) This amount is 150% of the hypothetical reset minimum quarterly distribution.

The following table illustrates the total amount of available cash from distributable cash flow that would be distributed to the unitholders and our general partner, including in respect of incentive distribution rights, or IDRs, based on an average of the amounts distributed for the two quarters immediately prior to the reset. The table assumes that immediately prior to the reset there would be 57,018,880 common units outstanding, our general partner has maintained its 2.0% general partner interest, and the average distribution to each common unit would be $0.60 for the two quarters prior to the reset.

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	Quarterly Distribution per Common Unit Prior to Reset	Cash Distributions to Common Unitholders Prior to Reset	Cash Distributions to General Partner Prior to Reset				Total Distributions
			Common Units	2.0% General Partner Interest	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	$0.3375	$ 19,243,872	$	$ 392,732	$	$ 392,732	$ 19,636,604
First Target Distribution	above $0.3375 up to $0.37125	1,924,387		45,280	294,318	339,598	2,263,985
Second Target Distribution	above $0.37125 up to $0.50625	7,697,549		205,268	2,360,582	2,565,850	10,263,398
Thereafter	above $0.50625	5,345,520		213,821	5,131,699	5,345,520	10,691,040
		$ 34,211,328	$	$ 857,101	$ 7,786,599	$ 8,643,699	$ 42,855,027

The following table illustrates the total amount of available cash from distributable cash flow that would be distributed to the unitholders and our general partner, including in respect of IDRs, with respect to the quarter in which the reset occurs. The table reflects that as a result of the reset there would be 69,996,545 common units outstanding, our general partner s 2.0% interest has been maintained, and the average distribution to each common unit would be $0.60. The number of common units to be issued to our general partner upon the reset was calculated by dividing (i) the average of the amounts received by our general partner in respect of its IDRs for the two quarters prior to the reset as shown in the table above, or $7,786,599, by (ii) the average available cash distributed on each common unit for the two quarters prior to the reset as shown in the table above, or $0.60.

	Quarterly Distribution per Common Unit at Reset	Cash Distributions to Common Unitholders at Reset	Cash Distributions to General Partner at Reset				Total Distributions
			Common Units	2.0% General Partner Interest	Incentive Distribution Rights	Total	
Minimum Quarterly Distribution	$0.60	$ 34,211,328	$ 7,786,599	$ 857,101	$	$ 8,643,699	$ 42,855,027
First Target Distribution	above $0.60 up to $0.66						
Second Target Distribution	above $0.66 up to $0.90						

Thereafter	above $0.90										
		$	34,211,328	$	7,786,599	$	857,101	$		$	8,643,699	$	42,855,027

Our general partner will be entitled to cause the minimum quarterly distribution amount and the target distribution levels to be reset on more than one occasion, provided that it may not make a reset election except at a time when it has received incentive distributions for the prior four consecutive fiscal quarters based on the highest level of incentive distributions that it is entitled to receive under our partnership agreement. Neither the existence of the reset right nor the exercise thereof will preclude our general partner from unilaterally foregoing the payment of all or a portion of the IDRs otherwise payable, whether temporarily or permanently.

Distributions From Capital Surplus

How Distributions from Capital Surplus Will Be Made. Our partnership agreement requires that we make distributions of available cash from capital surplus, if any, in the following manner:

first, 98.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit that was issued in this offering, an amount of available cash from capital surplus equal to the initial public offering price;

second, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until we distribute for each common unit, an amount of available cash from capital surplus equal to any unpaid arrearages in payment of the minimum quarterly distribution on the common units; and

thereafter, we will make all distributions of available cash from capital surplus as if they were from distributable cash flow.

The preceding paragraph assumes that our general partner maintains its 2.0% general partner interest and that we do not issue additional classes of equity securities.

Our partnership agreement includes a provision that will enable us, if we choose, to distribute up to $40 million of cash we receive in the future from sources other than distributable cash flow, such as asset sales, issuances of securities and borrowings, without being required to classify such distribution as a distribution from capital surplus under our partnership agreement. We do not anticipate that we will make any distributions from capital surplus.

Effect of a Distribution from Capital Surplus. Our partnership agreement treats a distribution of capital surplus as the repayment of the initial unit price from this initial public offering, which is a return of capital. The initial public offering price less any distributions of capital surplus per common unit is referred to as the unrecovered initial unit price. Each time a distribution of capital surplus is made, the minimum quarterly distribution and the target distribution levels will be reduced in the same proportion as the corresponding reduction in the unrecovered initial unit price. Because distributions of capital surplus will reduce the minimum quarterly distribution after any of these distributions are made, it may be easier for our general partner to receive incentive distributions, for the Series A subordinated units to convert into common units and the Series B subordinated units to convert into Series A subordinated units or common units. However, any distribution of capital surplus cannot be applied to the payment of the minimum quarterly distribution or any arrearages unless and until the unrecovered initial unit price is reduced to zero.

Once we distribute capital surplus on a unit issued in this offering in an aggregate amount equal to the initial unit price, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels will be reduced to zero. Our partnership agreement specifies that we then make all future distributions from distributable cash flow, with 50.0% being paid to the holders of units and 50.0% to our general partner. The percentage interest shown for our general partner include its 2.0% general partner interest and assume our general partner has maintained its 2.0% general partner interest and our general partner has not transferred the incentive distribution rights.

Adjustment to the Minimum Quarterly Distribution and Target Distribution Levels

In addition to adjusting the minimum quarterly distribution and target distribution levels to reflect a distribution of capital surplus, if we combine our common units into fewer common units or subdivide our common units into a greater number of common units, our partnership agreement specifies that the following items will be proportionately adjusted:

the minimum quarterly distribution;

the target distribution levels;

the unrecovered initial unit price; and

the number of Series A subordinated units and Series B subordinated units.

For example, if a two-for-one split of the common units should occur, the minimum quarterly distribution, the target distribution levels and the unrecovered initial unit price would each be reduced to 50% of its initial level, and each Series A subordinated unit and Series B subordinated unit would convert into two Series A subordinated units and two Series B subordinated units, respectively. Our partnership agreement provides that we do not make any adjustment by reason of the issuance of additional units for cash or property.

In addition, if legislation is enacted or if existing law is modified or interpreted by a governmental taxing authority, so that we become taxable as a corporation or otherwise subject to taxation as an entity for federal, state or local income tax purposes, our partnership agreement specifies that the minimum quarterly distribution and the target distribution levels for each quarter may be reduced by multiplying each distribution level by a fraction, the numerator of which is available cash for that quarter and the denominator of which is the sum of available cash for that quarter plus our general partner s estimate of our aggregate liability for the quarter for such income taxes payable by reason of such legislation or interpretation. To the extent that the actual tax liability differs from the estimated tax liability for any quarter, the difference will be accounted for in subsequent quarters.

Distributions of Cash Upon Liquidation

General. If we dissolve in accordance with the partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the general partner, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation.

The allocations of gain and loss upon liquidation are intended, to the extent possible, to entitle the holders of outstanding common units to a preference over the holders of outstanding subordinated units upon our liquidation, to the extent required to permit common unitholders to receive their unrecovered initial unit price plus the minimum quarterly distribution for the quarter during which liquidation occurs plus any unpaid arrearages in payment of the minimum quarterly distribution on the common units. However, there may not be sufficient gain upon our liquidation to enable the holders of common units to fully recover all of these amounts, even though there may be cash available for distribution to the holders of subordinated units. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of our general partner.

Although the Series B subordinated units will not be entitled to quarterly distributions, the Series B subordinated units would participate in distributions upon liquidation in accordance with their capital account balances. After conversion of the Series B subordinated units, special allocations of income, gain, loss, deduction, unrealized gain, and unrealized loss among the partners will be utilized to create economic uniformity among the units into which the Series B subordinated units convert.

Manner of Adjustments for Gain. The manner of the adjustment for gain is set forth in the partnership agreement. If our liquidation occurs before the end of the subordination period, we will generally allocate any gain to the partners in the following manner:

first, to our general partner and the holders of units who have negative balances in their capital accounts to the extent of and in proportion to those negative balances;

second, 98.0% to the common unitholders, pro rata, and 2.0% to our general partner, until the capital account for each common unit is equal to the sum of: (1) the unrecovered initial unit price; (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs; and (3) any unpaid arrearages in payment of the minimum quarterly distribution;

third, 98.0% to the Series A subordinated unitholders, pro rata, and 2.0% to our general partner, until the capital account for each Series A subordinated unit is equal to the sum of: (1) the unrecovered initial unit price; and (2) the amount of the minimum quarterly distribution for the quarter during which our liquidation occurs;

fourth, 85.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 15.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the first target distribution per unit over the minimum quarterly distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from distributable cash flow in excess of the minimum quarterly distribution per unit that we distributed 85.0% to the unitholders, pro rata, and 15.0% to our general partner for each quarter of our existence;

fifth, 75.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 25.0% to our general partner, until we allocate under this paragraph an amount per unit equal to: (1) the sum of the excess of the second target distribution per unit over the first target distribution per unit for each quarter of our existence; less (2) the cumulative amount per unit of any distributions of available cash from distributable cash flow in excess of the first target distribution per unit that we distributed 75.0% to the unitholders, pro rata, and 25.0% to our general partner for each quarter of our existence; and

thereafter, 50.0% to all common unitholders and Series A subordinated unitholders, pro rata, and 50.0% to our general partner.

The percentage interests set forth above for our general partner include its 2.0% general partner interest and assume our general partner has not transferred the incentive distribution rights.

If the liquidation occurs after the end of the subordination period, the distinction between common units and subordinated units will disappear, so that clause (3) of the second bullet point above and all of the third bullet point above will no longer be applicable.

We may make special allocations of gain among the partners in a manner to create economic uniformity among the units, including among the units into which the Series A subordinated units and Series B subordinated units convert, and among the common units issued in connection with a reset of the incentive distribution levels and the common units held by public unitholders.

Manner of Adjustments for Losses. If our liquidation occurs before the end of the subordination period, after making allocations of loss to the general partner and the unitholders in a manner intended to offset in reverse order the allocations of gains that have previously been allocated, we will generally allocate any loss to our general partner and the unitholders in the following manner:

first, 98.0% to holders of Series A subordinated units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the Series A subordinated unitholders have been reduced to zero;

second, 98.0% to the holders of common units in proportion to the positive balances in their capital accounts and 2.0% to our general partner, until the capital accounts of the common unitholders have been reduced to zero; and

thereafter, 100.0% to our general partner.

If the liquidation occurs after the end of the subordination period, the distinction between common units and Series A subordinated units will disappear, so that all of the first bullet point above will no longer be applicable.

We may make special allocations of loss among the partners in a manner to create economic uniformity among the units, including among the units into which the Series A subordinated units and Series B subordinated units convert, and among the common units issued in connection with a reset of the incentive distribution levels and the common units held by public unitholders.

Adjustments to Capital Accounts. Our partnership agreement requires that we make adjustments to capital accounts upon the issuance of additional units. In this regard, our partnership agreement specifies that we allocate any unrealized and, for tax purposes, unrecognized gain resulting from the adjustments to the unitholders and the general partner in the same manner as we allocate gain upon liquidation. In the event that we make positive adjustments to the capital accounts upon the issuance of additional units, our partnership agreement requires that we generally allocate any later negative adjustments to the capital accounts resulting from the issuance of additional units or upon our liquidation in a manner which results, to the extent possible, in the partners capital account balances equaling the amount which they would have been if no earlier positive adjustments to the capital accounts had been made. By contrast to the allocations of gain, and except as provided above, we generally will allocate any unrealized and unrecognized loss resulting from the adjustments to capital accounts upon the issuance of additional units to the unitholders and our general partner based on their respective percentage ownership of us. In this manner, prior to the end of the subordination

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period, we generally will allocate any such loss equally with respect to our common and Series A subordinated units. In the event we make negative adjustments to the capital accounts as a result of such loss, future positive adjustments resulting from the issuance of additional units will be allocated in a manner designed to reverse the prior negative adjustments, and special allocations will be made upon liquidation in a manner that results, to the extent possible, in our unitholders capital account balances equaling the amounts they would have been if no earlier adjustments for loss had been made.

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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

The selected financial and operating data below was derived from our audited consolidated balance sheets as of December 31, 2009 and 2008, and the audited consolidated statements of operations, changes in members capital and cash flows for the periods of September 3, 2009 to December 31, 2009, January 1, 2009 to September 2, 2009, and the years ended December 31, 2008 and 2007 included elsewhere in this prospectus. The selected historical financial and operating data below for the years ended December 31, 2007, 2006 and 2005 was derived from our audited consolidated balance sheet as of December 31, 2007, 2006 and 2005 and the consolidated statements of operations, changes in members capital and cash flows for the years ended December 31, 2006 and 2005 not included in this prospectus.

On September 3, 2009, PAA became our sole owner by acquiring Vulcan Capital s 50% interest in us (the PAA Ownership Transaction) in exchange for $220 million, including contingent cash consideration of $40 million. At the time of the transaction, the entity had approximately $450 million of outstanding project finance debt. Although we continued as the same legal entity after the transaction, pursuant to applicable accounting principles, all of our assets and liabilities were adjusted to fair value as a result of this transaction. This change in value resulted in a new cost basis for accounting (fair value push down accounting). Accordingly, the selected financial and operating data presented below are presented for two periods, Predecessor and Successor, which relate to the accounting periods preceding and succeeding the PAA Ownership Transaction. The Predecessor and Successor periods have been separated by a vertical line to highlight the fact that the financial and operating information for such periods was prepared under a different basis of accounting.

The summary pro forma statement of operations data for the year ended December 31, 2009 and the summary pro forma balance sheet data as of December 31, 2009 are derived from our unaudited pro forma condensed combined financial statements included elsewhere in this prospectus. The pro forma adjustments have been prepared as if the PAA Ownership Transaction, this offering and the anticipated borrowings under our credit facility had taken place on December 31, 2009 in the case of the pro forma balance sheet, and on January 1, 2009 in the case of the pro forma statement of operations data. A more complete explanation of the pro forma data can be found in our unaudited pro forma condensed combined financial statements.

The selected historical and pro forma financial and operating data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Management s Discussion and Analysis of Financial Condition and Results of Operations.

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	Predecessor					Successor	Pro Forma
	August 18, 2005 through December 31, 2005(1)	Year Ended December 31, 2006	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1, 2009 through September 2, 2009	September 3, 2009 through December 31, 2009	Year Ended December 3 2009
	($ in thousands except for /Mcf numbers)						
atement of operations ta:							
otal revenues	$ 6,580	$ 30,831	$ 36,945	$ 49,177	$ 46,929	$ 25,251	$ 72,180
orage related costs		100	3,847	8,934	8,792	7,003	15,795
perating costs (except ose shown below)	1,180	3,658	3,947	4,059	4,820	3,257	8,077
el expense	411	613	1,140	2,320	1,816	578	2,394
eneral and ministrative expenses	866	3,402	3,755	3,874	3,562	4,083	8,897
epreciation, depletion d amortization	1,223	3,986	4,520	6,245	8,054	3,578	12,242
otal costs and expenses	3,680	11,759	17,209	25,432	27,044	18,499	47,405
perating income	2,900	19,072	19,736	23,745	19,885	6,752	24,775
terest expense	(1,684)	(8,389)	(7,108)	(4,941)	(4,352)	(4,262)	(759
terest income and other come (expense), net	480	2,030	5,378	1,669	458	(2)	456
come tax expense				(887)	(473)		(473
et income	$ 1,696	$ 12,713	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 23,999
lance sheet data (at d of period):							
otal assets	$ 332,002	$ 518,092	$ 674,765	$ 811,436		$ 900,407	$ 900,407
ong-term debt(2)	85,500	227,300	352,713	415,263		450,523	200,000
otal debt(2)	85,500	227,300	355,163	417,713		450,523	200,000
embers /partners capital	226,696	264,109	294,717	363,229		432,744	683,267
ther financial data:							
djusted EBITDA(3)	$ 4,603	$ 27,395	$ 29,663	$ 31,001	$ 28,701	$ 12,165(4)	$ 39,614
stributable cash flow(3)	$ 2,919	$ 19,006	$ 22,156	$ 25,577	$ 23,965	$ 7,200	$ 37,768
aintenance capital penditures	$	$	$	$ 377	$ 384	$ 320	$ 704
et cash provided by sed in) operating tivities	$ 5,351	$ 13,973	$ 22,343	$ 21,818	$ 22,603	$ 15,265	
	$ (264,189)	$ (206,612)	$ (177,280)	$ (118,890)	$ (58,561)	$ (9,656)	

et cash provided by sed in) investing tivities							
et cash provided by sed in) financing tivities	$ 309,278	$ 158,771	$ 145,743	$ 122,344	$ 23,636	$ (22,813)	
perating data:							
verage monthly working pacity (Bcf)(5)(6)	20	24	26	28	40	43	41
verage monthly Firm orage Services venue/Mcf	$ 0.08	$ 0.09	$ 0.10	$ 0.13	$ 0.13	$ 0.14	$ 0.14
verage monthly Hub rvices revenue/Mcf	$ 0.01	$ 0.01	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.01
djusted EBITDA/Mcf	$ 0.23	$ 1.14	$ 1.14	$ 1.11	$ 0.72	$ 0.28	$ 0.97

(1) Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. In September 2005, we entered the gas storage business through the acquisition of the Bluewater facility in the start-up phase and certain land and development rights of Pine Prairie in the

permitting phase. The assets we acquired constituted only a small portion of the seller s total assets and detailed, segregated financial information regarding these assets for the eight months ended August 31, 2005 was not maintained and cannot be provided without unreasonable effort and expense. Due to the significant growth and development of our business since September 2005, the age of this information and its limited comparability to more current period information, we believe that the omission of financial information for this eight month period of 2005 is immaterial and unnecessary with respect to an understanding of our financial results and condition or any related trends or business prospects.

(2) At December 31, 2009 on a historical basis, the long-term debt and total debt balances consist of an intercompany note payable to PAA. At December 31, 2009 on a pro forma basis, the long-term debt and total debt balances consist of borrowings under our new revolving credit facility.

(3) Adjusted EBITDA and distributable cash flow are defined in Summary Summary Historical Financial and Operating Data Non-GAAP and Segment Financial Measures. Distributable cash flow does not reflect actual cash on hand that is available for distribution to our unitholders. For a discussion of the limitations on our cash distributions and our general partner s ability to change our cash distribution policy, please read Our Cash Distribution Policy and Restrictions on Distributions General Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy.

(4) The successor period includes total expenses of approximately $1 million associated with increased personnel costs, including added staffing, and accelerated audit and other costs related to our increased acquisition activities and our efforts to become a publicly traded entity as well as increased overhead allocations from PAA.

(5) Includes up to 3 Bcf of storage capacity under lease from third parties.

(6) Calculated as the sum of the capacity at the end of each month divided by the number of months in the period.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of financial condition and results of operations in conjunction with our historical consolidated financial statements included elsewhere in this prospectus. Among other things, those historical financial statements include more detailed information regarding the basis of presentation for the following discussion. In addition, you should read Forward-Looking Statements and Risk Factors for information regarding certain risks inherent in our business.

Overview

We are a fee-based, growth-oriented Delaware limited partnership formed by Plains All American in January 2010 to own, operate and grow the natural gas storage business that PAA acquired in 2005 and has continuously operated since that time. Concurrent with the closing of this offering, PAA will contribute the equity interest in the entities that own its natural gas storage business to us. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. We currently own and operate two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively.

Our operating assets include the Pine Prairie facility, which is a recently constructed, high-deliverability salt-cavern natural gas storage complex located in Evangeline Parish, Louisiana, and the Bluewater facility, which is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. Pine Prairie has a total current working gas storage capacity of 14 Bcf in two salt caverns, and Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs.

Activities Impacting Our Historical and Anticipated Growth

Our gas storage facilities have been expanded, are undergoing current expansion or present additional organic growth opportunities for future expansion. These ongoing expansion activities have affected operating and financial results since 2005 and are expected to affect our future results. We have budgeted approximately $260 million for all of our planned organic growth capital expenditures through 2012, $95 million of which we plan to spend in 2010, $85 million of which we plan to spend in 2011 and $80 million of which we plan to spend in 2012. A description of our historical and planned expansion activities is set forth below.

Pine Prairie. Since we acquired the development rights and assets of Pine Prairie in 2005, we have developed and placed into service two salt caverns with an aggregate working gas storage capacity of 14 Bcf. Our first storage cavern (5 Bcf) went into service in October 2008 and the second storage cavern (9 Bcf) went into service in March 2009. Our current expansion plans include the addition of 31 Bcf of working gas storage capacity at our Pine Prairie facility, 28 Bcf of which we expect to place into service by mid-2012, including 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. We have received all applicable federal, state and local approvals required to construct these expansions (including FERC and Louisiana Department of Natural Resources) and, when complete, we expect to have five salt caverns in service and 45 Bcf of working gas storage capacity at Pine Prairie. We have also constructed a pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, that connects directly to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as

Gulf of Mexico production and LNG imports. In connection with our current plan to expand Pine Prairie to five caverns, we are in the process of adding approximately 56,250 horsepower of compression to supplement the approximately 32,000 horsepower already in place. Pine Prairie also has a solution mining facility (used to create salt-dome storage caverns) that is capable of leaching at an aggregate rate of up to 8,000 gallons of water per minute. Our total estimated capital cost for all of our existing facilities at Pine Prairie and the planned expansions to take our working gas storage capacity to 45 Bcf is expected to be approximately $738 million, excluding capitalized interest, approximately $504 million of which had been spent as of December 31, 2009. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account, with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

Bluewater. We acquired the Bluewater facility in 2005 at the same time we acquired the development rights and assets of Pine Prairie. At the time we acquired Bluewater, it had an aggregate working gas storage capacity of 20 Bcf. Since the acquisition, we have completed various expansion activities that enabled us to raise the maximum operating pressure of the Bluewater facility, which in turn increased the total storage capacity of the initial Bluewater facility to 23 Bcf. During 2006, we acquired the nearby Kimball depleted reservoir storage facility and integrated it with our extensive pipeline header system at Bluewater, which provided an additional 3 Bcf of storage capacity and enhanced our operating flexibility. During the second quarter of 2010, we commenced drilling of an additional well within the main portion of the larger reservoir, which we believe will create additional natural gas storage capacity by allowing removal of liquids from the reservoir that could not be produced from existing well bores. Any liquid hydrocarbons recovered will be sold to generate additional revenue, and any water produced will be removed from the reservoir. The project also involves re-configuring our compression to optimize our existing injection and deliverability capacity. We expect the total cost of the project to be approximately $9 million, including incremental base gas requirements. Although we can give no assurance that the project will be successful, we currently estimate that the project will increase the Bluewater facility s total storage capacity by approximately 2 Bcf ratably over a 10-year period beginning in 2011.

Factors That Impact Our Business

We believe that the high percentage of our earnings derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers stabilizes our baseline cash flow profile, and substantially mitigates the risk to us of significant negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. We do not take title to the natural gas that we store for our customers, but we are entitled to retain a small portion of the natural gas scheduled for injection by our customers to compensate us for the natural gas we use as fuel to run our facilities. Except for (i) the base gas we purchase and use in our facilities and which we consider a long-term asset, and (ii) volume and pricing variations related to fuel retained from our customers, our current and planned business strategies are designed to minimize our exposure to fluctuations in the outright price of natural gas.

We believe key factors that influence our business are (i) the long-term demand for natural gas in our markets and the overall balance in our markets between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis, which factors determine the amount of volatility in natural gas prices and drive the month to month differentials in the forward curve for natural gas prices, (ii) the needs of our customers and the competitiveness of our service offerings with respect to price, reliability and flexibility, and (iii) government regulation of natural gas storage systems. These key factors, discussed in more detail below, play an important role in how we evaluate our operations and implement our long-term strategies.

Natural Gas Supply and Demand Dynamics

To effectively manage our business, we monitor our market areas for both short-term and long-term changes in natural gas supply and demand and the relative adequacy of existing and planned pipeline and storage infrastructure to meet these changing needs. In general, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase volatility, inter-month differentials in gas prices and the need for and value of storage services. Our storage services allow our customers to manage volatility in natural gas supply and demand, as well as price, throughout our markets. As changes in natural gas supply and demand dynamics take place, we will attempt to adjust our service offerings in terms of price, term, operating flexibility and other factors to meet the needs of our customers, in each case subject to any regulatory constraints or limitations provided in our FERC-approved tariffs.

Customers and Competition

We store natural gas and provide other storage services for a broad mix of customers, including LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. Our Pine Prairie and Bluewater facilities are located in two different markets. Bluewater is located in the Midwestern U.S. and its function and value is generally related to supply and demand imbalances resulting from seasonal factors. Pine Prairie is a multi-turn, high-performance facility located in the Gulf Coast that provides seasonal-related services as well as a variety of other services. Collectively, these facilities are strategically positioned relative to several major market hubs and have significant connectivity that enable them to serve a variety of major producing regions, LNG importers and the primary consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the U.S. as well as eastern Ontario, Canada.

In general, the mix of services we provide to our customers varies depending on market conditions, expectations for future market conditions and the overall competitiveness of our service offerings. The storage markets in which we operate are very competitive and we compete with other storage operators on the basis of rates, terms of service, types of service, supply and market access, and flexibility and reliability of service. We continuously monitor the evolving needs of our customers, current and forecasted market conditions and the competitiveness of our service offerings in order to maintain the proper balance between optimizing near-term earnings and cash flow and positioning the business for sustainable long-term growth.

Regulation

Government regulation of natural gas storage can have a significant impact on our business. The rates and terms and conditions for the interstate storage services provided by our Pine Prairie and Bluewater facilities are set forth in FERC-approved tariffs, which currently permit both Pine Prairie and Bluewater to charge market-based rates. Market-based rate authority allows Pine Prairie and Bluewater to negotiate rates with individual customers based on market demand. The right to charge market-based rates may be challenged by a party filing a complaint with the FERC or by the FERC on its own initiative. Any successful complaint or protest against our rates could have an adverse impact on our revenues associated with providing storage services. Other federal and state regulation can impact our operations, cost structure and profitability, which could in turn impact our financial performance and our ability to make distributions to our unitholders. As a result, we closely monitor regulatory developments affecting our business. For more information, see Business Regulation.

How We Evaluate Our Operations

We evaluate our business performance on the basis of the following key measures:

- revenues derived from both firm storage services and hub services;
- our operating and general and administrative expenses;
- our Adjusted EBITDA; and

our distributable cash flow.

We do not utilize depreciation, depletion and amortization expense in our key measures, because we focus our performance management on cash flow generation and our assets have long useful lives.

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In our period to period comparisons of our revenues and expenses set forth below, we analyze the following revenue and expenses components:

Revenues

Firm storage reservation fees. Firm storage services include (i) storage services pursuant to which customers receive the assured or firm right to store gas in our facilities over a multi-year period and (ii) seasonal park and loan services pursuant to which customers receive the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis. Under our firm storage contracts, our customers are obligated to pay us fixed monthly capacity reservation fees, which are owed to us regardless of the actual storage capacity utilized. At Pine Prairie, our firm storage contracts typically have terms of 3 to 5 years, while at Bluewater terms generally range from 1 to 3 years.

Firm storage cycling fees and fuel-in-kind. We also typically collect a cycling fee based on the volume of natural gas nominated for injection and/or withdrawal and retain a small portion of natural gas nominated for injection as compensation for our fuel use.

Hub services. We collect fees from (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) non-seasonal park and loan services and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from our facilities. We may also retain a small portion of natural gas nominated for injection as compensation for our fuel use.

Other revenues. We also generate revenues through the sale of crude oil and liquids produced in conjunction with the operation of our Bluewater facility, net of royalties and taxes. Additionally, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed as fuel for our facilities and reflect any gain or loss on such sales in other revenues.

Expenses

Storage related costs. These consist of fees incurred to lease third-party storage and pipeline capacity and costs associated with certain loan services.

Fuel expense. Natural gas constitutes the primary fuel for our compressors, which are used to inject natural gas into our storage facilities and to boost the pressures for certain pipeline deliveries or transfers. Fuel-related expenses may fluctuate materially from period to period due to variations in both the volume and value of natural gas consumed in our operations, with volumes being driven primarily by the volumes of natural gas injected into or wheeled through our facilities. We measure our fuel consumption using meters located at our central facilities. We charge fuel expense for the estimated volume consumed based on the weighted average price of fuel collected.

General and Administrative Expense. Excluding fuel-related expenses, our operating and general and administrative expenses typically do not materially vary based on the amount of natural gas we store. The timing of certain expenditures during a year generally fluctuate with customers demands, which change depending on market conditions and whether we are in the injection or withdrawal season for natural gas. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. Fluctuations in operating costs may occur due to the timing of planned maintenance activities as well as fluctuations in the level of project development and acquisition activity during a given period of time. Regulatory compliance can also impact our maintenance requirements and affect the timing and amount of our costs and expenditures.

Adjusted EBITDA and Distributable Cash Flow

Adjusted EBITDA and distributable cash flow are supplemental financial measures that are used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring.

Adjusted EBITDA may be used to assess:

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

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

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

Distributable cash flow will be determined by our general partner and is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received.

Distributable cash flow may be used to assess our ability to generate sufficient cash flow to make distributions of the minimum quarterly distribution on all of our outstanding units as well as to satisfy the tests necessary for the conversion of our Series B subordinated units into Series A subordinated units or common units and the conversion of our Series A subordinated units into common units.

The GAAP measure most directly comparable to Adjusted EBITDA and distributable cash flow is net income. The supplemental measures of Adjusted EBITDA and distributable cash flow should not be considered as alternatives to GAAP net income. These measures have important limitations as an analytical tool because they exclude some but not all items that affect net income. You should not consider Adjusted EBITDA or distributable cash flow in isolation or as a substitute for net income, cash from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility. For a reconciliation of these measures to their most directly comparable financial measure calculated and presented in accordance with GAAP, please see Summary Summary Historical Financial and Operating Data Non-GAAP and Segment Financial Measures.

Management compensates for the limitations of Adjusted EBITDA and distributable cash flow as analytical tools by reviewing the comparable GAAP measure, understanding the differences between such measures and net income, and incorporating this knowledge into its decision-making processes. We believe

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that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results.

Results of Operations

PAA Ownership Transaction and Basis of Presentation

On September 3, 2009, PAA became our sole owner by acquiring Vulcan Capital s 50% interest in us (PAA Ownership Transaction) in exchange for $220 million, including contingent cash consideration of $40 million, which we expect to be paid, and the obligation to pay 100% of our outstanding project finance debt of approximately $450 million. Although we continued as the same legal entity after the transaction, pursuant to applicable accounting principles, all of our assets and liabilities were adjusted to fair value as a result of the transaction. This change in value resulted in a new cost basis for accounting (fair value push down accounting). Accordingly, the accompanying consolidated financial statements are presented for two periods, Predecessor and Successor, which relate to the accounting periods preceding and succeeding the PAA Ownership Transaction. The Predecessor and Successor periods have been separated by a vertical line on the face of our consolidated financial statements to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting. We have prepared our discussion of the results of operations by comparing the results of operations of the Predecessor for the years ended December 31, 2007 and 2008 to the Predecessor period of January 1, 2009 to September 2, 2009. A comparative discussion of the results of operations of the Successor period of September 3, 2009 to December 31, 2009 has not been provided due to the lack of a comparable 2008 operating period for Predecessor; however, we have prepared a brief discussion of the factors that materially affected our operating results in the Successor period. We have provided a comparative discussion of the pro forma results of operations of the year ended December 31, 2009 (prepared as if the PAA Ownership Transaction, this offering and the anticipated borrowing under our credit facility had taken place on January 1, 2009) to the year ended December 31, 2008. The following table includes our operating results for these periods (dollar amounts in thousands, except per Mcf amounts).

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	Predecessor			Successor	Pro Forma
	Year Ended December 31,		January 1, 2009 through September 2, 2009	September 3, 2009 through December 31, 2009	Year Ended December 31, 2009
	2007	2008			
Revenues					
Firm storage services					
Reservation fees	$ 28,542	$ 37,674	$ 39,616	$ 22,919	$ 62,535
Cycling fees and fuel-in-kind	2,815	5,197	3,033	1,053	4,086
Hub Services	4,802	1,417	2,988	1,637	4,625
Other	786	4,889	1,292	(358)	934
Total revenue	36,945	49,177	46,929	25,251	72,180
Storage related costs	(3,847)	(8,934)	(8,792)	(7,003)	(15,795)
Operating costs (except those shown below)	(3,947)	(4,059)	(4,820)	(3,257)	(8,077)
Fuel expense	(1,140)	(2,320)	(1,816)	(578)	(2,394)
General and administrative expenses	(3,755)	(3,874)	(3,562)	(4,083)	(8,897)
Interest income and other income (expense), net	5,378	1,669	458	(2)	456
Equity compensation expense	553	(110)	304	1,467	1,771
Mark-to-market of open derivative positions	(524)	(548)		370	370
Adjusted EBITDA	29,663	31,001	28,701	12,165	39,614
Reconciliation to net income					
Depreciation, depletion and amortization	(4,520)	(6,245)	(8,054)	(3,578)	(12,242)
Interest expense[1]	(7,108)	(4,941)	(4,352)	(4,262)	(759)
Income tax expense		(887)	(473)		(473)
Equity compensation expense	(553)	110	(304)	(1,467)	(1,771)
Mark-to-market of open derivative positions	524	548		(370)	(370)
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 23,999
Operating Data:					
Average monthly working capacity (Bcf)	26	28	40	43	41
Average monthly Firm Storage Services revenue/Mcf	$ 0.10	$ 0.13	$ 0.13	$ 0.14	$ 0.14
Average monthly Hub Services revenue/Mcf	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.01
Adjusted EBITDA/Mcf	$ 1.14	$ 1.11	$ 0.72	$ 0.28	$ 0.97

(1) Interest expense is net of capitalized interest of $18.6 million, $19.0 million, $10.2 million, $5.4 million and $7.5 million for the periods presented, respectively.

Pro forma period of 2009 and 2008

The following discussion and analysis compares the pro forma results of operations for the year ended December 31, 2009 to our predecessor s historical results of operations for the year ended December 31, 2008. As the pro forma results of operations are not necessarily indicative of operating results had the transactions occurred January 1, 2009, this discussion is not a substitute for management s discussion and analysis on a historical basis.

Revenues, Volumes and Storage Related Costs. As noted in the table above, our total revenue and storage related costs increased for the year ended December 31, 2009 on a pro forma basis (2009 pro forma period) as compared to the year ended December 31, 2008 (the 2008 period). This increase primarily resulted from our second Pine Prairie facility cavern being placed into operation in April 2009. Significant additional variances related to these periods are discussed below:

Firm storage reservation fees Firm storage reservation fee revenues increased for the 2009 pro forma period as compared to the 2008 period, primarily due to an additional 8 Bcf of capacity being placed into service at Pine Prairie during 2009, along with a full year of operations for our initial 6 Bcf of capacity at Pine Prairie. Our Pine Prairie facility generated approximately $19.4 million of incremental firm storage services revenues during the 2009 pro forma period. Revenues from firm storage reservation fees were also positively impacted by loan transactions and third-party transportation activities together with increases in storage leased from third parties for the 2009 pro forma period when compared to the 2008 period. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues decreased in the 2009 pro forma period as compared to the 2008 period primarily due to a decrease in the period over period average natural gas price of approximately 53% in the 2009 pro forma period, which was partially offset by increased volumes collected primarily due to an additional 8 Bcf of capacity being placed into service at our Pine Prairie facility.

Hub services Hub services increased approximately $3.2 million in the 2009 pro forma period as compared to the 2008 period. This increase was primarily related to increased wheeling and balancing services through the utilization of transportation capacity during the 2009 pro forma period. See Storage related costs below.

Other Other revenue for each of the periods was comprised primarily of crude oil sales. The decrease in the 2009 pro forma period as compared to the 2008 period was primarily related to lower average prices realized in the 2009 pro forma period. Additionally, other revenue during the 2008 period reflects a realized gain of approximately $1.1 million on a natural gas storage related futures derivative position. Other revenue for the 2009 pro forma period includes an unrealized loss of approximately $0.4 million on a natural gas storage related futures derivative position.

Storage related costs We increased the amount of storage and transportation capacity leased from third parties in the 2009 pro forma period compared to the 2008 period. In addition, we experienced higher costs as a result of increased loan transactions in the 2009 pro forma period compared to the 2008 period.

Other Costs and Expenses. The significant variances are discussed further below:

Operating costs Field operating costs increased in the 2009 pro forma period compared to the 2008 period. This increase is primarily related to our continued expansion of the Pine Prairie facility and related growth in personnel costs.

Fuel expense Fuel expense was relatively flat in the 2009 pro forma period compared to the 2008 period as an increase in volumes used was largely offset by a decrease in the average price of natural gas.

General and administrative expenses General and administrative expenses increased in the 2009 pro forma period compared to the 2008 period. This increase was driven by increased costs primarily related to the continued expansion of our business and growth in personnel costs, including an increase in costs allocated to us from PAA as a result of PAA personnel devoting additional time and effort to our operations.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2009 pro forma period compared to the 2008 period. This increase was driven primarily by an increased amount of depreciable assets resulting from our internal growth projects (including our second Pine Prairie facility cavern) along with an increase in the basis of property and equipment as a result of fair value adjustments recorded in connection with the PAA Ownership Transaction. These increases were partially offset by adjustments to the estimated useful lives of our property and equipment in conjunction with the PAA Ownership Transaction which lengthened the estimated useful lives of most of our more significant components of property and equipment. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $2.6 million and $1.4 million in the 2009 pro forma period and 2008 period, respectively.

Interest expense Interest expense decreased in the 2009 pro forma period as compared to the 2008 period. This decrease was principally due to the reduction in our debt balance as a result of the use of the net offering proceeds to pay down approximately $233.9 million of our intercompany note payable to PAA and the decrease in interest rate associated with the $200 million of credit facility borrowings which were used to pay down our note payable to PAA. Interest expense for the 2009 pro forma period reflects that the intercompany indebtedness not repaid in connection with this offering was extinguished and treated as a capital contribution and part of PAA s investment in us. The pro forma interest rate on borrowings under our new credit facility is 3.5%, which is based on an assumed rate based on a forecast of LIBOR rates during the period plus the margin and associated commitment fees under the new credit facility, whereas the interest rate on the intercompany note payable to PAA is 6.5%. The impact of this interest rate differential was offset by higher average debt balances and a decrease in capitalized interest in the 2009 pro forma period as compared to the 2008 period. The amount of interest capitalized decreased from approximately $19 million for the 2008 period to approximately $7.5 million for the 2009 pro forma period. The decrease resulted from lower levels of capitalized interest expense as a result of the commencement of operations on caverns one and two of our Pine Prairie facility.

Income tax expense Income tax expense consists of the Michigan state income tax, which was effective January 1, 2008. This tax is an apportionment tax and the commencement of operations at our Pine Prairie facility effectively diluted the activity apportioned to Michigan. Our activity apportionable to Michigan was further diluted when we became a consolidated subsidiary of PAA, which under Michigan tax law resulted in our being required to report for tax purposes on a consolidated basis with PAA. Such factors resulted in a decrease in income tax expense in the 2009 pro forma period when compared to the 2008 period.

Interest Income and Other Income (Expense), Net Interest income and other income (expense), net is comprised primarily of interest income and decreased for the 2009 pro forma period compared to the 2008 period primarily due to a decrease in our average cash balances. The year over year decreases in interest income was also impacted by lower average interest rates for the 2009 pro forma period as compared to the 2008 period.

Successor Period of 2009

Because the PAA Ownership Transaction did not impact our operations, there were no significant changes in the underlying trends affecting our results of operations. The following discussion compares our operating results between the period beginning January 1, 2009 and ending September 2, 2009 (the 2009 Predecessor Period) and the period beginning September 3, 2009 and ending December 31, 2009 (the 2009 Successor period), as well as discusses certain factors that materially affected our operating results in the 2009 Successor period.

Revenues, volumes and storage related costs. During the 2009 Successor period, our average monthly working capacity was approximately 43 Bcf, which was an increase over the 40 Bcf average monthly working capacity for the 2009 Predecessor period. This increase was primarily as a result of the commencement of operations of our second cavern at the Pine Prairie facility in April 2009. The increased storage capacity resulted in higher average monthly revenue and storage and transportation related costs. In addition, our average monthly revenues increased as we expanded our services through loans and increased third-party storage and transportation related activities. These increased activities also resulted in higher costs during the 2009 Successor period.

Operating costs and general and administrative expenses. Average monthly field operating costs and general and administrative costs increased during the 2009 Successor period. The increase is primarily related to the continued expansion of our business and growth in personnel costs, including staff additions as we prepared for becoming a publicly traded entity, increased acquisition evaluation activity, a portion of which is reflected in increased allocations from PAA subsequent to the PAA Ownership Transaction, and the fact the joint venture agreement in place with Vulcan Capital prior to the PAA Ownership Transaction did not permit PAA to charge us for executive officer expenses.

Depreciation, depletion and amortization. Average monthly depreciation, depletion and amortization expense was impacted in the 2009 Successor period by (i) the change in the cost basis of our property and equipment resulting from the fair value push down accounting and additional assets being placed into service, offset by (ii) an increase in the estimate of the useful lives of our facilities and related property and equipment resulting from the valuation assessment conducted in coordination with the fair value push down accounting adjustments. (see Note 2 to our Consolidated Financial Statements). On an annual basis, depreciation decreased approximately $2.7 million as a result of the change in the depreciable lives. This was partially offset by an increase in annual depreciation of approximately $2.3 million resulting from the increase in the fair values as a result of the PAA Ownership Transaction.

Interest expense. In conjunction with the PAA Ownership Transaction, we entered into an intercompany note payable to PAA and used the proceeds therefrom to repay outstanding project finance debt and terminate our outstanding credit facilities. See Liquidity and Capital Resources. Our average debt outstanding under the note payable, primarily associated with financing the construction of our Pine Prairie facility, increased during the 2009 Successor period to an average of approximately $442 million. In addition, we capitalized interest of approximately $5.4 million, which is a lower percentage of overall interest than we have capitalized in prior periods, due to lower balances of construction in progress as we have commenced operations of our first two caverns at our Pine Prairie facility. The increased average debt balances, higher average interest rate and lower capitalized interest resulted in an increase in average monthly interest expense during the 2009 Successor period.

Income tax expense. Income tax expense consists of the Michigan state income tax, which was effective January 1, 2008. This tax is an apportionment tax and the consolidation of our operations by PAA effectively diluted the activity apportioned to Michigan resulting in a significant decrease in income tax expense for the 2009 Successor period.

Interest income and other income (expense), net. Interest income and other income (expense), net has historically been comprised primarily of interest income related to our cash balances, which were required to be maintained under the terms of our Pine Prairie revolving credit facility. Following the termination of the credit facilities, we no longer carry significant cash balances and do not expect a material amount of interest income.

Predecessor Periods of 2009, 2008 and 2007

Revenues, Volumes and Storage Related Costs. As noted in the table above, our total revenue and storage related costs decreased for the 2009 Predecessor period compared to the 2008 period. The primary reason for the decreases is that the 2009 Predecessor period was approximately eight months and is being compared to a twelve-month period. This was partially offset in both cases by the second Pine Prairie facility cavern being placed into operation in April 2009. Total revenue and related storage and transportation costs for the 2008 period increased as compared to the year ended December 31, 2007 (the 2007 period). Significant additional variances related to these periods are discussed below:

> *Firm storage reservation fees* Firm storage reservation fee revenues increased for the 2009 Predecessor period as compared to the 2008 period, primarily due to the second Pine Prairie facility cavern being placed into operation, resulting in approximately $10.8 million in incremental revenues generated by our Pine Prairie facility for the 2009 Predecessor period. This more than offset the decrease in firm storage reservation fees caused by the shorter 2009 Predecessor period. Firm storage revenues increased for the 2008 period as compared to the 2007 period as we sold additional firm storage capacity and entered into fewer seasonal parks, which allowed us to capture the market premium that our customers were placing on firm storage services.

This increase in firm storage reservation fees was partially offset by decreases in our hub services as discussed below. Firm storage reservation fees were also positively impacted by the commencement of operations at our first cavern at our Pine Prairie facility, which contributed approximately $1.4 million of additional revenue during the 2008 period. Revenues from firm storage reservation fees were also positively impacted by loan and third-party transportation activities together with increases in storage leased from third parties for both the 2009 Predecessor period and the 2008 period. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues decreased in the 2009 Predecessor period as compared to the 2008 period primarily due to a decrease in the period over period average natural gas price of approximately 56% in the 2009 Predecessor period as well as the shorter 2009 Predecessor period, which was partially offset by increased volumes collected primarily due to the second Pine Prairie facility cavern being placed into operation. These revenues increased in the 2008 period as compared to the 2007 period primarily due to an increase in the period over period average natural gas prices of approximately 25%, combined with an increase in volumes collected.

Hub services Hub services increased approximately $1.6 million in the 2009 Predecessor period as compared to the 2008 period. This increase was primarily related to an increased amount of wheeling and balancing services through the utilization of transportation capacity during the 2009 Predecessor period. See Storage related costs below. These increases offset the impact caused by the shorter 2009 Predecessor period as compared to the 2008 period. Hub services decreased approximately $3.4 million in the 2008 period as compared to the 2007 period. The decrease was primarily due to an increase in the amount of firm storage capacity that we sold resulting in less capacity available for non seasonal parks. See Firm storage reservation fees above.

Other Other revenue for each of the periods was comprised primarily of crude oil sales. The decrease in the 2009 Predecessor period as compared to the 2008 period was primarily related to lower average prices realized in the 2009 Predecessor period. The increase in the 2008 period over the 2007 period was primarily related to higher average prices and increased volumes sold. In addition, the 2008 period includes a financial derivative gain of approximately $1.1 million from natural gas storage related futures position.

Storage related costs We increased the amount of storage and transportation capacity leased from third parties in both the 2009 Predecessor period and the 2008 period as compared to the applicable prior period. In addition, we experienced higher costs as a result of increased loan transactions in each period. The increased costs were partially offset by the shorter 2009 Predecessor period.

Other Costs and Expenses. The significant variances are discussed further below:

Operating costs Field operating costs increased in the 2009 Predecessor period and 2008 period as compared to the applicable prior periods. The increases in these periods are primarily related to our continued expansion of the Pine Prairie facility and related growth in personnel costs. The increase in costs in the 2009 Predecessor period was partially offset by the shorter 2009 Predecessor period.

Fuel expense Fuel expense was relatively flat in the 2009 Predecessor period as compared to the 2008 period as an increase in volumes used was offset by a decrease in the average price of natural gas. Fuel expense increased in the 2008 period as compared to the 2007 period as both volumes and the average price of natural gas increased.

General and administrative expenses General and administrative expenses decreased in the 2009 Predecessor period as compared to the 2008 period primarily as a result of the shorter 2009 Predecessor period. That decrease was partially offset by increased costs primarily related to the continued expansion of our business and growth in personnel costs. General and administrative expenses were relatively flat for the 2008 period as compared to the 2007 period.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in both the 2009 Predecessor period and 2008 period as compared to the applicable prior periods. The respective increases related primarily to an increased amount of depreciable assets stemming from our internal growth projects. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $2.2 million, $1.4 million and $0.9 million in the 2009 Predecessor period, 2008 period and 2007 period, respectively.

Interest expense Interest expense decreased in the 2009 Predecessor period as compared to the 2008 period primarily because of the shorter 2009 Predecessor period, but also because of lower average interest rates. That decrease was partially offset by a higher average debt balance for the 2009 Predecessor period and a lower percentage of capitalized interest. The amount of interest capitalized decreased from approximately $19 million for the 2008 period to approximately $10 million for the 2009 Predecessor period. The decrease resulted from lower levels of capitalized interest expense as a result of the commencement of operations on caverns one and two of our Pine Prairie facility. Interest expense decreased for the 2008 period from the 2007 period primarily due to lower average interest rates and slightly higher capitalized interest compared to approximately $18.6 million for the 2007 period. The decrease was partially offset by increased average debt balances during the 2008 period.

Income tax expense Income tax expense consists of the Michigan state income tax, which was effective January 1, 2008. This tax is an apportionment tax and the commencement of operations at our Pine Prairie facility effectively diluted the activity apportioned to Michigan resulting in a decrease in expense for the 2009 Predecessor period as compared to the 2008 period. Because this tax was not effective until January 1, 2008, we recognized no such tax expense in the 2007 period.

Interest Income and Other Income (Expense), Net Interest income and other income (expense), net is comprised primarily of interest income and decreased for the 2009 Predecessor period and 2008 period as compared to the applicable prior periods primarily due to a decrease in our average cash balances. The year over year decreases in interest income were also impacted by lower average interest rates for the 2009 Predecessor period and 2008 period as compared to the applicable prior periods.

Future Trends and Outlook

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

Benefits from Organic Growth Projects. We expect that our results from operations for the year ending December 31, 2010 and thereafter will benefit from increased revenues associated with our ongoing expansion projects. At our Pine Prairie facility, we are nearing completion of a third storage cavern that we expect will have 10 Bcf of working gas capacity that we expect to place into service during the second quarter of 2010. In addition, as part of our current development plan, our expansion plans include an additional 21 Bcf of working gas storage capacity, 18 Bcf of which we expect to place into service by mid-2012. We have received regulatory approval for these expansions, and when completed as designed, we will have five salt caverns in service and 45 Bcf of working gas storage capacity at Pine Prairie. At Bluewater, we are pursuing a liquids removal project that is targeted to increase Bluewater s total storage capacity by approximately 2 Bcf ratably over a 10-year period beginning in 2011.

Growing Natural Gas Demand. Publications by the EIA and other industry sources forecast continued growth of long-term demand for natural gas, as well as a continuation of the historical trend of growth in natural gas demand from seasonal and weather-sensitive consumption sectors. The various factors supporting these forecasts include (i) expectations of continued growth in the U.S. gross domestic product, which exerts a significant influence on long-term growth in natural gas demand, (ii) an increased likelihood that regulatory and legislative initiatives regarding U.S. carbon policy will drive greater demand for cleaner burning fuels like natural gas, (iii) increasing acceptance of the view that fossil fuels will continue to provide the vast majority of total energy used in the U.S. for the foreseeable future and that natural gas is a clean and abundant domestic fuel source, and (iv) continued growth in electricity generation from intermittent renewable energy sources, primarily wind and solar energy, for which natural-gas fired generation is a logical back-up power supply source.

Natural Gas Supply. For the foreseeable future we believe there will be ample supplies of natural gas from a combination of domestic production, pipeline imports and waterborne imports of LNG. We also believe, however, that it is difficult to predict the extent to which domestic production from unconventional shale resources and LNG imports will increase or decrease, and that this source of supply uncertainty adds an element of volatility to natural gas markets that will drive greater demand for storage services, especially from well-positioned facilities that can provide customers with access to both LNG imports and shale production.

Market Volatility. Our business can be positively or negatively affected by the widening or narrowing of seasonal spreads, extended periods of significant or little volatility and economic expansions or downturns.

Barriers to Entry. Although competition within the storage industry is robust, significant barriers to entry exist in the natural gas storage business. These barriers include significant costs and execution risk, a lengthy permitting and development cycle, financing challenges, shortage of personnel with the requisite expertise and the finite number of storage sites suitable for development.

Supply of Storage Capacity. An important factor in determining the value of storage and therefore the rates we are able to charge for new contracts or contract renewals is whether a surplus or shortfall of storage capacity exists relative to the overall demand for storage services in a given market area. In general, on a relative basis, storage values will be lower in markets that are oversupplied with storage than in markets where storage capacity is in short supply. The extent to which markets are oversupplied or undersupplied will fluctuate in response to significant variations in natural gas supply and demand. We believe that the current market for storage capacity is undersupplied. However, future market conditions will be determined both by the future demand for storage as well as the net amount of storage capacity added in future years.

Commercial Management Activities. Similar to the business model successfully employed by PAA, and without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year firm storage contracts at attractive rates, during 2010 we intend to establish a dedicated commercial marketing group that will capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. Consistent with PAA s experience marketing crude oil and refined products, we believe a dedicated commercial marketing group that has a consistent presence in our markets will enhance our ability to properly price our storage and hub service offerings and will increase our cash flow by capitalizing on volatility and inefficiencies in the natural gas markets. We will conduct these commercial activities within pre-defined risk parameters, and our general policy will be (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flow and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

Maintenance Capital Expenditures. Maintenance capital expenditures reduce our distributable cash flow and consist of cash capital expenditures made for the purpose of maintaining or replacing the operating capacity, service capability and/or functionality of our existing assets. Examples of maintenance capital expenditures include capital expenditures associated with maintaining the storage capacity of our facilities as well as ongoing maintenance or replacement costs for the various injection, withdrawal and related equipment associated with those facilities. Our maintenance capital expenditures are not significant because our storage facilities and related equipment are relatively new. We would expect maintenance capital expenditures to increase periodically as we undertake scheduled maintenance on our caverns and related equipment. Although these periodic costs may increase our maintenance capital expenditures from time to time, we do not expect these increases to materially impact our operating results or distributable cash flow.

Operating Costs and Inflation. High levels of natural gas exploration, development and production activities across the U.S. can result in increased competition for personnel and equipment. This can cause an increase in the prices we pay for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect. We will attempt to recover any increased costs from our customers, but there may be a delay in doing so or we may be unable to recover all these costs. To the extent we are unable to procure necessary supplies or recover higher costs, our operating results will be negatively impacted.

Increased Costs as a Result of Being a Public Entity. As a result of being a publicly traded limited partnership, we will incur incremental general and administrative expenses that are not reflected in our historical financial statements. These costs include costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees, Sarbanes-Oxley compliance, New York Stock Exchange listing, investor relations activities, registrar and transfer agent fees, director and officer liability insurance costs and director compensation. We expect our incremental general and administrative expenses associated with being a publicly traded limited partnership to total approximately $2.6 million per year.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of natural gas storage assets. Such acquisition efforts involve our participation in processes that have been made public, involve a number of potential buyers and are commonly referred to as auction processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

In connection with our acquisition activities, we routinely incur evaluation and due diligence costs, which are expensed as incurred. In addition to the in-house costs of our personnel and ancillary overhead expenditures allocated to us by our general partner for time devoted to evaluating acquisition opportunities (which can be substantial), we also budget approximately $250,000 per year associated with third party evaluation or due diligence costs for transactions that are assumed not to be consummated.

Working with PAA, we are currently involved in discussions and, in certain cases, negotiations, with a number of potential sellers regarding the purchase of natural gas storage assets. Certain of these discussions are more advanced than others, but past experience has demonstrated that any of these discussions and negotiations could advance or terminate in a short period of time. Because of the current increased level of activity, however third party expenses may exceed our typical budgeted levels in the near term. Additionally, certain of the opportunities under evaluation are of a size that would likely involve PAA s assistance with respect to financing or jointly purchasing such assets. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Potential PAA Financial Support. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us. See Risk Factors If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

Liquidity and Capital Resources

Overview. Our ability to finance our operations, including funding capital expenditures, making acquisitions, making cash distributions and satisfying any indebtedness obligations, will depend on our ability to generate cash in the future. Our ability to generate cash remains subject to a number of factors, some of which extend beyond our control. See Risk Factors for further discussion regarding such risks that may affect our liquidity and capital resources.

Prior to September 3, 2009, our activities were conducted in a joint venture arrangement. Accordingly, cash flow from operations, borrowings under our credit facilities and contributions from equity owners were historically our primary sources of liquidity. On September 3, 2009, PAA became our sole owner by acquiring Vulcan s 50% interest in us. In conjunction with that transaction, we entered into a note payable to PAA for approximately $421 million. The proceeds of the note payable were used to repay amounts borrowed under our credit facilities and related interest rate swaps. The credit facilities were terminated following their repayment. The note payable accrues interest at a rate of

6.5%. The proceeds of this offering, as well as anticipated borrowings under our credit facility, will be utilized to reduce the amount outstanding under this note payable by approximately $433.9 million. We expect that any intercompany indebtedness not repaid in

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connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us.

Currently, our sources of liquidity include cash generated from operations and funding from PAA. Subsequent to this offering, we expect our sources of liquidity to include:

cash generated from operations;

borrowings under a newly established credit facility with a group of banks;

issuances of additional partnership units; and

debt offerings.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements, and quarterly cash distributions to unitholders.

To maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for expansion projects with equity and cash flow in excess of distributions. In connection with this offering, we entered into a new $400 million revolving credit facility. We believe we will be able to fund up to the first $250 million of acquisitions or expansion projects primarily through borrowings under this credit facility or through other sources and remain in compliance with our targeted credit profile.

For a discussion of the impact that the price of natural gas might have on our operations and liquidity and capital resources, please read Quantitative and Qualitative Disclosures About Market Risk.

Working Capital. Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven primarily by changes in accounts receivable and accounts payable. These changes are primarily affected by factors such as credit extended to, and the timing of collections from, our customers and our level of spending for maintenance and expansion activity. We had a working capital balance of approximately $29 million as of December 31, 2008. As of December 31, 2009, we had a working capital deficit of approximately $4 million, primarily as a result of PAA s election to fund our capital requirements through the intercompany note with PAA following the PAA Ownership Transaction.

Historical cash flow information. The following table reflects cash flows for the applicable periods (in thousands):

	Predecessor			**Successor**
	Year Ended December 31, 2007	**Year Ended December 31, 2008**	**January 1, 2009 through September 2, 2009**	**September 3, 2009 through December 31, 2009**
Net cash provided by (used in):				
Operating activities	$ 22,343	$ 21,818	$ 22,603	$ 15,265
Investing activities	$ (177,280)	$ (118,890)	$ (58,561)	$ (9,656)
Financing activities	$ 145,743	$ 122,344	$ 23,636	$ (22,813)

Operating Activities. The primary drivers of cash flow from our operations are (i) the collection of amounts related to the storage of natural gas, and (ii) the payment of amounts related to expenses, principally storage and transportation related costs, field operating costs and general and administrative expenses. Cash flow from operations increased for the 2009 Predecessor period as compared to the 2008 period primarily due to increased storage activity resulting from the commencement of activities at our Pine Prairie facility in late 2008 and early 2009. These increases were offset by the shorter time period in the 2009 Predecessor period. In addition, 2008 operating activities were negatively affected by approximately $3.2 million for a payment made to the Industrial Development Board No. 1 of the Parish of Evangeline, State of Louisiana, Inc. with respect to a tax abatement for our Pine Prairie facility (see Note 8 to our Consolidated Financial Statements for further discussion). Operating cash flows for the 2008 period decreased from the prior year primarily as a result of the payment to the Parish, which was partially offset by increased storage activity in the 2008 period as compared to the prior year.

Investing and Financing Activities. Our investing activities for each of the periods listed above primarily relate to the continued expansion of our Pine Prairie facility and the acquisition of the related base gas required to operate the facility. See Activities Impacting Our Historical and Anticipated Growth above. To fund these expenditures we made borrowings under our previous credit facilities and term loan agreements and received capital contributions from our equity owners.

Distributions to our unitholders and general partner. Our partnership agreement requires us to distribute all of our available cash quarterly. Generally, our available cash is our cash on hand at the end of the quarter after the payment of our expenses and the establishment of cash reserves and cash on hand resulting from borrowings, including working capital borrowings, made after the end of the quarter. We anticipate paying a minimum quarterly distribution of $0.3375 per common unit and Series A subordinated unit per complete quarter, which equates to $15.7 million per quarter, or $62.7 million per year, based on the number of common units, Series A subordinated units and the general partner interest expected to be outstanding immediately after completion of this offering. We do not have a legal obligation to pay this distribution unless and until a quarterly distribution is declared. See Our Cash Distribution Policy and Restrictions On Distributions for further information.

Capital Requirements. Our expansion plans include an additional 31 Bcf of working gas storage capacity at our Pine Prairie facility, of which 10 Bcf is substantially complete and expected to be in service during the second quarter of 2010. At Bluewater, we are pursuing a liquids removal project targeted to increase Bluewater s total storage capacity by approximately 2 Bcf ratably over a 10-year period beginning in 2011. We currently forecast capital expenditures for 2010 of approximately $95 million, primarily related to the Pine Prairie expansion and purchases of related base gas required to operate the facility. We expect to fund our capital expenditures with cash generated from operations and borrowings under our credit facility.

New Credit Facility. In connection with this offering, we entered into a new $400 million revolving credit facility, with a maturity date 3 years from the closing of this offering. The credit facility is available to fund working capital and our expansion projects, make acquisitions and for general partnership purposes. We expect that we will incur approximately $200 million of borrowings under our credit facility at the closing of this offering. As a result, we expect to have approximately $200 million of remaining capacity immediately after the closing, subject to compliance with any applicable covenants under the facility. Our new credit facility also has an accordion feature that allows us to increase the available borrowings under the facility to $600 million, subject to the satisfaction of certain closing conditions, including the identification of lenders or proposed lenders that agree to satisfy the increased commitment amounts under our new facility.

This new credit facility restricts our ability to, among other things:

- make distributions of available cash to unitholders if any default or event of default (as defined in the credit agreement) exists or would result therefrom;
- incur additional indebtedness;
- grant or permit to exist liens or enter into certain restricted contracts;
- engage in transactions with affiliates;
- make any material change to the nature of our business;

- make a disposition of all or substantially all of our assets; or
- enter into a merger, consolidate, liquidate, wind up or dissolve.

Furthermore, our credit facility contains covenants requiring us to maintain certain financial ratios related to our consolidated EBITDA, consolidated interest charges and consolidated funded indebtedness, as such terms are defined in our credit agreement.

Restrictions due to PAA s indebtedness. Although we are not contractually bound by and are not liable for PAA s debt under its debt instruments, we are subject to and indirectly affected by certain prohibitions and limitations contained therein. These restrictions may prevent us from obtaining the most advantageous financing terms or from engaging in certain transactions that might otherwise be considered beneficial. See Risk Factors We are considered a subsidiary of PAA under its debt instruments and, as such, we may be directly or indirectly subject to and impacted by certain restrictions in PAA s existing and future credit facilities and indentures. These restrictions may limit our access to credit, prevent us from engaging in beneficial activities, and in certain circumstances, require us to guarantee PAA s indebtedness. Although we believe that the restrictions in PAA s debt instruments will not have a material impact on our operations or access to credit, no assurance can be given to that effect, and PAA s ability to comply with any restrictions in PAA s debt instruments may be affected by events beyond our control.

Potential PAA Financial Support

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA s ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. In that regard, the following forms of potential PAA financial support will be deemed fair to our unitholders, and will not constitute a breach of any duty by our general partner, if consummated on terms not less favorable than those described below:

- our issuance of common units to PAA at a price per common unit of no less than 95% of the trailing 20-day average closing price per common unit.

- our borrowing funds from PAA on terms that include a tenor of no more than three years and a fixed rate of interest that is no more than 100 basis points higher than the lesser of (i) the fixed rate of interest incurred by PAA on any senior notes or other financial instruments issued by PAA to fund such loan to us or (ii) the weighted average of PAA s outstanding senior note issues.

- PAA may provide us or any of our subsidiaries with guaranties or trade credit support to support the ongoing operations of us or our subsidiaries; *provided, that* (i) the pricing for any such guaranties or trade credit support is no more than the cost to us of issuing a comparable letter of credit under our credit agreement, and (ii) any such guaranties or trade credit support are limited to ordinary course obligations of us or our subsidiaries and do not extend to indebtedness for borrowed money or other obligations that could be characterized as debt.

We have no obligation to seek financing or support from PAA on the terms described above or to accept such financing or support if offered to us. In addition, PAA will have no obligation to provide financial support under these or any other circumstances. We would anticipate that PAA would provide such support to us only if permitted under the relevant provisions of its debt instruments at the time. The existence of these provisions will not preclude other forms of financial support from PAA, including financial support on significantly less favorable terms under circumstances in which such support appears to be in our best interests.

In addition, following the completion of our issuance of common units in connection with an underwritten public offering, direct placement and/or private offering of common units, we may make a reasonably prompt redemption of a number of common units owned by PAA that is no greater than the aggregate number of common units issued to PAA pursuant to the first bullet above (taking into account any prior redemptions pursuant to this paragraph) at a price per common unit that is no greater than the price per common unit paid by the investors in such offering or placement, as applicable, less underwriting discounts and commissions or placement fees, if any. As with the transactions described in the bullets above, any such redemptions will be deemed fair to our unitholders and will not constitute a breach of any duty of our general partner.

Potential Impact of Recent Economic and Financial Market Trends. During 2008 and the first portion of 2009, worldwide financial markets were extremely volatile, the economy weakened considerably and there was widespread uncertainty regarding the health and stability of our banking system and financial markets.

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Early in 2009, capital markets access was very limited. As a result of substantial government intervention, the absence of another widespread calamity and the passage of time, panic subsided, and financial markets stabilized, successively becoming more and more favorable for capital formation over the remainder of 2009 and through the first few months of 2010.

In connection with this offering, we entered into a new $400 million revolving credit facility. We believe the borrowings available to us under this committed facility in combination with cash flow in excess of our distributions will enable us to fund our existing expansion activities for the next several years, while maintaining credit metrics consistent with our targeted credit profile. Funding of additional expansion activities or acquisitions will require us to access additional capital resources, which we intend to fund with approximately 60% equity capital and 40% debt capital. Although we believe that the equity and debt markets are currently available to us on reasonable terms, there can be no assurance that future market conditions will permit us to access capital to fund future acquisition and expansion activities.

We will not be unaffected by challenging economic and capital markets conditions or fluctuations in the price of natural gas; however, our business strategy and financial strategy are designed to help us manage through a volatile environment. In general, our assets and our business model benefit from volatility in the price of natural gas, whether natural gas prices are high or low relative to historical averages. Although an extended period of high gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated expansion activities, such conditions would also result in higher competitive entry barriers and higher demand for contract renewals on our existing storage and planned storage. An extended period of low natural gas prices could adversely impact storage values for a time. Such conditions have typically been self correcting, as positive demand response typically results, increasing natural gas consumption and accentuating seasonal imbalances and the demand for storage. A low gas price environment also typically increases competitive entry barriers and reduces our cost of incremental base gas and storage construction costs.

We anticipate our future working capital needs will increase modestly in connection with our expansion into commercial optimization activities. Revenues generated from these activities will be influenced by natural gas prices, which have been volatile and unpredictable in the past. While we expect this volatility to continue in the future, we consider our exposure to commodity price risk not to be material based on the amount of revenues associated with these activities compared to our overall revenues and the fact that the balance of our revenues is fee-based.

See Business Our Financial Strategy for a description of our financial strategy and Risk Factors Risks Related to Our Business.

Off-balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Contingencies

For a discussion of contingencies that may impact us, see Note 8 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business we lease storage and transportation capacity from third parties. We also incur debt and interest payments. The following table includes our best

estimate of the amount and timing of the payments due under our contractual obligations as of December 31, 2009 (in thousands):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest payments(1)	$ 651,415	$	$	$	$	$ 651,415	$
Leases storage, transportation, other	51,118	16,103	11,822	10,522	6,228	4,448	1,995
Purchase obligations	41,718	23,512	1,556	1,800	1,800	1,800	11,250
Other long-term liabilities	1,097		808	145	137	4	3
Total	$ 745,348	$ 39,615	$ 14,186	$ 12,467	$ 8,165	$ 657,667	$ 13,248

(1) Includes intercompany loan of $451 million and interest of 6.5% for 5 years entered into in connection with the PAA Ownership Transaction. The loan is represented by a demand note payable to PAA. PAA has issued a waiver stating that it will not demand payment during the year ended December 31, 2010, and PAA has indicated that it will not request repayment prior to December 31, 2013. In connection with the closing of this offering, we expect to repay approximately $433.9 million of this indebtedness. We expect that any intercompany indebtedness not repaid in connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us.

Upon the consummation of this offering, we expect to incur long-term debt under our new credit facility of $200 million, which will be used, together with the net proceeds of this offering, to repay intercompany indebtedness owed to PAA. We expect the initial interest rate under our new credit facility to be LIBOR plus a margin of 2.5% and we expect the commitment fees will be approximately 0.4% on unborrowed commitments, subject in each case to adjustment based on our consolidated leverage ratio (as defined in our credit facility). Additionally, in connection with the closing of this offering, we will enter into an omnibus agreement with PAA pursuant to which, among other things, PAA s general partner will provide to us certain general and administrative services and employees. Pursuant to the omnibus agreement, we will be obligated to reimburse PAA s general partner for all reasonable costs and expenses incurred by it in connection with the performance of these services and for PAA s provision of employees.

Quantitative and Qualitative Disclosures About Market Risk

From time to time, we may use derivative instruments to (i) manage our exposure to interest rates or natural gas prices associated with future base gas purchases and (ii) economically hedge the intrinsic value of our natural gas storage facilities.

Commodity Price Risk

Natural Gas. We do not take title to the natural gas that we store for our customers and, accordingly, are not exposed to commodity price fluctuations on the gas that is stored in our facilities by our customers. Except for the base gas we purchase and use in our facilities, which we consider to be a long-term asset, and volume and pricing variations related to small volumes of fuel-in-kind natural gas that we are entitled to retain from our customers as compensation for our fuel costs, our current business model is designed to minimize our exposure to fluctuations in the outright price of natural gas. As a result, absent other market factors that could adversely impact our operations, changes in the price of natural gas should not materially impact our operations.

With respect to base gas, we typically use derivative instruments to hedge all or some portion of our anticipated base gas purchases. In addition, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed for our facilities, and we may also purchase fuel in excess of our fuel-in-kind volumes to the extent such volumes are needed to operate our facilities.

Our derivatives at December 31, 2009 represented a net liability of $0.4 million; a 10% decrease in natural gas prices would result in an incremental liability of $0.3 million.

Oil. We generate a relatively small amount of revenue through the sale of crude oil and liquids incrementally produced from our Bluewater facility and, accordingly, are exposed to commodity price fluctuations on the volumes of crude oil and liquids produced and sold from our Bluewater facility. Given the fact that crude oil sales generate a relatively small amount of our revenue and that the volumes produced are difficult to predict, we do not typically attempt to hedge the value of such sales.

Commercial Activities. During 2010 we intend to establish a dedicated commercial marketing group that will capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. We will conduct these commercial activities within pre-defined risk parameters, and our general policy will be (i) to purchase natural gas only in situations where we have a market for such gas, (ii) utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that price fluctuations will not have a material adverse impact on our cash flow, and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

Revenues generated from these activities will be subject to the pricing of hydrocarbons, which has been volatile and unpredictable in the past. While we expect this volatility to continue in the future, we consider our exposure to commodity price risk not to be material based on the amount of revenues associated with these activities compared to our overall revenues and the fact that the balance of our revenues is fee-based.

Interest Rate Risk

Interest rates in recent years have been low compared to rates over the last 50 years. If interest rates were to rise, our financing costs would increase accordingly. Although increased borrowing costs could limit our ability to raise funds in the capital markets, we expect our competitors would be similarly affected.

Prior to the PAA Ownership Transaction, amounts outstanding under our credit facilities accrued interest at floating rates, which were hedged with interest rate swaps. In conjunction with the PAA Ownership Transaction, we entered into a note payable to PAA for approximately $421 million. The proceeds of the note payable were used to repay amounts borrowed under our then-existing credit facilities and related interest rate swaps. The note payable to PAA accrues interest at a fixed rate of 6.5%. At the closing of this offering, we will incur approximately $200 million of borrowings under a new credit facility, which will bear interest at floating rates. We intend to enter into interest rate swaps to fix the interest rate of borrowings under the new credit facility. If we fail to do so, to the extent the interest rate on borrowings under our new credit facility increases or decreases by 1%, interest on amounts outstanding will increase or decrease, respectively, by approximately $2 million.

Critical Accounting Policies and Estimates

Critical Accounting Policies

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with GAAP. These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting estimates that we have identified are discussed below.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with FASB guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimated provision will be recognized. This provision will be adjusted as if the amount was recognized when the combination occurred if material. We also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful lives as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management s estimate of market conditions including pricing, demand, competition, operating costs and other factors. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as customer relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management s assessment of the value of the assets acquired and, to the extent available, third-party assessments. Uncertainties associated with these estimates include assumptions regarding natural gas supply and demand, volatility and pricing of natural gas, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable.

We did not have any goodwill impairments in 2009, 2008 or 2007. See Note 2 to our Consolidated Financial Statements for a discussion of goodwill.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate the estimated useful lives of our property, plant and equipment and revised our estimates in September 2009. Please read Note 2 to our Consolidated Financial Statements.

We also evaluate our property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The impairment evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of holding versus selling an asset;
- the forecast of undiscounted expected future cash flow over the asset s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

No impairments have been recorded since our inception.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, insurance claims, asset retirement obligations, taxes and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Such accruals may include estimates and are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory requirements for operating gas storage facilities, costs of medical care associated with worker s compensation and employee health insurance claims, and the possibility of legal claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. Presently, there are no material accruals in these areas. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Equity Compensation Plan Accruals. We will accrue compensation expense for outstanding equity awards granted under our Long Term Incentive Plan. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable.

For equity compensation awards prior to this offering, the total compensation expense initially allocated to us by PAA over the service period is determined by multiplying PAA s unit price by the number of equity awards that are expected to vest, plus our share of associated employment taxes. Uncertainties associated with these accruals include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

We anticipate that, in connection with the closing of this offering, the board of directors of our general partner will grant awards to our key employees and our outside directors pursuant to the Long Term Incentive Plan. Certain of our key employees hold grants under PAA s Long Term Incentive Plan. It is our intent to replace such grants with grants of equivalent value under our Long Term Incentive Plan.

We recognized total compensation expense of approximately $1.5 million, $0.3 million, $(0.1) million and $0.6 million in the 2009 Successor period, 2009 Predecessor period, and the years ended December 31, 2008 and 2007, respectively, related to equity awards granted under the various equity compensation plans, which are allocated to us by PAA. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 6 to our Consolidated Financial Statements.

Mark-to-Market Accrual. In situations where we are required to mark-to-market derivatives pursuant to FASB guidance, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market-observable inputs such as price, volatility, correlation and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our Consolidated Financial Statements.

NATURAL GAS STORAGE INDUSTRY

Introduction

Natural gas storage facilities represent a critical component of the North American natural gas transmission and distribution system. These facilities provide an essential reliability cushion against unexpected disruptions in supply, transportation or markets and allow for the warehousing of gas to meet expected seasonal, monthly and daily variability in demand. The diagram below illustrates the position and function of natural gas storage within the natural gas market chain.

We believe that changes in natural gas markets over the last 25 years have contributed to a growing demand for natural gas storage services provided by independent storage operators like us, particularly with respect to strategically-located, high-performance facilities. Factors contributing to this growing market include (a) a major shift in the manner in which natural gas sales, transportation and storage are regulated; (b) changes in the manner of sale of natural gas, including the development of a futures market and a cash spot market; (c) changes in the composition of natural gas consumption and political and environmental pressures that appear to directionally support increased consumption of natural gas; and (d) the dynamic and evolving profile of various sources of natural gas supply. The overview below provides additional information regarding the current and potential demand for storage as well as the various types of natural gas storage facilities, the services they provide and other related information.

Overview

Historical Context. The current market environment for natural gas storage has evolved significantly since the 1970s as the market for natural gas has become less regulated. During this time period, various developments have contributed to the emergence of an open and less regulated market for natural gas sales and natural gas storage, including:

- interstate pipelines and intrastate utilities were required to unbundle their merchant, transportation and storage services, allowing storage services to be provided by non-pipeline service providers at market-based rates (as opposed to traditional cost-of-service based rates);

- *take-or-pay* contracts were eliminated through a combination of regulation and litigation. Under take-or-pay arrangements, purchasers would pay for a minimum quantity of natural gas during a contract year even if the actual amount of gas received by the purchaser was less than the stated minimum. These contracts permitted purchasers to effectively dictate sellers production schedules, directing the producers as to when to turn on or turn off their contracted wells. Excess production capacity of sellers represented significant in situ natural gas storage capacity and deliverability that was utilized by purchasers to meet seasonal or other peak demand requirements. The elimination of these contractual arrangements afforded sellers the ability to produce natural gas on a year-round basis and contract directly with end-users;

a spot market for natural gas developed and the NYMEX introduced the natural gas futures contract in April 1990; and

primarily as a result of continuous production and direct competition among gas sellers, natural gas prices fell and consumption increased. According to the EIA, natural gas consumption increased an average of 1% annually from 1990 to 2008.

Over this same time period, the purpose and use of natural gas storage has evolved, expanding from a service that was used almost exclusively by local distribution companies and pipelines to balance seasonal or other demand variations, as well as to balance system loads and facilitate pipeline movements, into a service that is used by a wider variety of customers. These expanded services developed for multiple commercial purposes, including:

to ensure fuel availability for peak loads by gas-fired power generation;

to reduce the impact of supply interruptions in the Gulf of Mexico resulting from hurricanes and other severe weather;

to accommodate increased balancing requirements associated with erratic and rapidly declining initial production profiles of new wells in developing shale resource plays or wells that needed to produce continuously without regard to current market demand or price in order to optimize recovery;

to contribute to the commercial optimization activities of natural gas suppliers and consumers or financial arbitrage and risk management activities of commodity traders and other market participants;

to facilitate storage and distribution of intermittent LNG cargoes; and

to manage the variability of solar and wind power generation by providing a back-up fuel source to support gas-fired power generating facilities.

As a result of the increased consumption of natural gas over the last two decades, the changes in domestic production capacity and the increased demand for natural gas storage services from a wide variety of market participants, natural gas storage currently plays a critical role in maintaining the reliability and availability of gas supplies in North America.

Storage Services. Storage operators compete for customers based on geographical location, which determines connectivity to pipelines and proximity to supply sources and end-users, as well as operating reliability and flexibility, price, available capacity and service offerings. Services provided by storage operators typically include firm storage services and hub services.

Firm Storage Services. Customers pay a fixed monthly capacity reservation fee in exchange for an assured or firm right to store, inject or withdraw specified volumes for specified periods of time. Capacity reservation fees are payable without regard to the amount of storage capacity actually utilized. Firm storage customers also typically pay cycling fees based on the volume of natural gas nominated for injection and/or withdrawal on any given day.

Hub Services. Hub services include (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the future availability of capacity in a storage facility and pay fees based on their actual utilization of storage capacity and services, (ii) park and loan services, pursuant to which customers pay fees for the right to store gas in (park), or borrow gas from (loan), a storage facility and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through a storage facility from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from, a storage facility.

From the storage operator s perspective, having a diverse customer group that requires a variety of storage services is important to maximizing asset utilization and capturing incremental revenue opportunities while minimizing costs.

Types of Storage Facilities. Natural gas is typically stored underground in depleted reservoirs, aquifers or salt caverns. In any non-salt cavern underground storage facility, there is a certain amount of natural gas that may never be extracted, referred to as physically unrecoverable, or permanent, natural gas. In addition to this permanent gas, underground storage facilities contain what is known as base gas, or cushion gas. This is the volume of gas that is injected into a storage facility to maintain adequate pressure and deliverability rates, especially throughout the withdrawal season. In general, working gas is the volume of natural gas in a storage facility at a given point in time that exceeds the amount of base gas and, if applicable, physically unrecoverable gas. Assuming adequate operating pressures, working gas is the amount of gas that can be extracted during the normal operation of the facility. References to the capacity of a storage facility typically refer to its working gas capacity.

Based on our review of publicly available information, we estimate that depleted natural gas or oil reservoirs comprise approximately 85% of total working gas storage capacity in the United States. Depleted reservoir facilities are prevalent in the producing regions of the United States, primarily the Northeast, Midwest, Gulf Coast and West Coast regions. Aquifer storage facilities are primarily located in the Midwest. Most salt-cavern storage facilities have been developed in salt-dome formations located along the Gulf Coast, with more limited development in bedded salt formations located in Northeastern, Midwestern and Southwestern states. Based on our review of publicly available information, we estimate that natural aquifers and salt caverns comprise approximately 9% and 6%, respectively, of total working gas storage capacity in the United States.

The key distinguishing operational characteristics of any given storage facility, aside from its overall capacity, are its peak injection and withdrawal rates, which dictate the number of times during a given year that a facility is capable of being turned or cycled (i.e., completely filled with injections of working gas and then completely emptied by withdrawals) and its connectivity to different pipelines and/or markets. Higher peak injection and withdrawal rates and access to multiple markets provide storage users with greater commercial and operational flexibility and, accordingly, command higher storage rates. Salt caverns are voided underground spaces and natural gas can be freely injected into and withdrawn from such caverns with the aid of compression. Conversely, depleted reservoirs and aquifers store natural gas within pore spaces in rock formations and the ability of natural gas to move into and out of the facility is limited by the permeability of the applicable formations, even with the aid of compression. As a result, salt caverns generally have significantly higher peak injection and withdrawal rates, and can be cycled more times per year, than depleted reservoirs and aquifers.

Other important characteristics of storage facilities include the overall cost of developing the facility, including base gas requirements and geological risk.

Cost to Develop. The primary categories of cost associated with the development of natural gas storage facilities are (i) real and personal property acquisition costs, (ii) equipment purchase costs, (iii) costs associated with construction, and (iv) the cost of acquiring base gas, which is required to maintain operating pressures and allow for working gas withdrawals. With respect to construction and other non-base gas costs, depleted reservoir facilities are usually the least expensive to develop as portions of existing pipeline and facility infrastructure related to prior production operations can often be used in connection with the development and operation of a depleted reservoir facility, reducing up-front infrastructure costs. In terms of base gas costs, which represent an additional up-front investment cost for a storage facility operator, according to a 2004 FERC report on underground natural gas storage, salt caverns typically require the lowest levels of base gas at approximately 20 to 30% of total gas capacity. By comparison, depleted reservoirs typically require approximately 50% base gas and aquifers may require up to 80% base gas.

Geological Risks. A critical attribute of any underground gas storage facility is the integrity of the geological structure in which the natural gas is stored. The geology of depleted reservoirs is typically well understood and the risk of gas leaks is relatively low given their prior natural use for storing

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hydrocarbons. The risk of gas leaks from salt caverns is also relatively low given that the walls of a properly constructed salt cavern provide a non-porous seal that reduces the likelihood of gas leaks. Aquifers typically have a higher level of geological risk because they have not previously been used to store hydrocarbons.

Barriers to Entry. Although competition within the storage industry is robust, there are significant barriers to entering the natural gas storage business. These barriers include:

Costs and Execution Risk. The costs of developing and constructing an underground storage facility are significant and highly variable, depending on drilling costs, subsurface issues, raw water availability, brine disposal arrangements, compression requirements, costs of establishing interconnects and other factors. In addition, the creation of all three types of storage facilities involves significant execution risk with respect to drilling and completing wells and related sub-surface activities.

Time Commitment. The length of time required to permit and develop a new project and place it into service can be long and unpredictable, generally ranging from two to four years or more, depending on the type of facility, location, permitting issues, subsurface issues and other factors.

Financing. The magnitude and uncertainty of capital costs, length of the permitting and development cycle and scheduling uncertainties associated with gas storage development present significant project financing challenges. In recent years, the tightening of credit markets has led to a reduction in the amount of capital available for natural gas storage projects.

Finite Number of Sites. Finding and developing new gas storage facilities, or acquiring existing facilities, is extremely competitive given that there are a finite number of sites that possess the requisite characteristics in terms of proximity to pipelines and load centers, operational flexibility, geological characteristics and overall risk/return profile.

Required Expertise. Specialized expertise is required to identify market areas that require or will support additional storage capacity. In addition, acquiring, developing and operating natural gas storage facilities involves identifying, assessing and managing significant geological and other risks that require specialized industry knowledge and experience, including in the areas of reservoir engineering and geology, cavern or reservoir development and construction, and gas compression, handling, treating and transportation. Because there is significant market demand for this combination of skill sets and individuals with such skills sets are in short supply, finding and retaining management and operational personnel is highly competitive.

Drivers of Demand for Storage. The long-term demand for storage services in the United States is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and value of storage services.

Natural Gas Demand. According to the EIA, as shown in the chart below, during the period from 1998 through 2008, natural gas consumption increased by 4.1% overall from an average of approximately 60.9 Bcf per day in 1998 to an average of approximately 63.4 Bcf per day in 2008. Although the change in consumption levels during this period was variable on a year-to-year basis, growth was highest in the seasonal and weather-sensitive electric power generation and commercial/residential sectors, where consumption grew by approximately 45.2% and 6.2%, respectively. The growth in these sectors was partially offset by an approximate 20.5% decline in gas consumption in the less seasonal industrial sector.

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Percentage Change In Consumption 1998-2008:

Residential & Commercial	6.2%
Industrial	–20.5%
Electric Power	45.2%
Total Consumption	4.1%

Source: derived from EIA data

Despite the increased use of natural-gas fired generation during the summer cooling months and the recent trend of warmer winters, the seasonality of natural gas consumption has remained strong. According to EIA data, during the last decade, consumption during the winter months averaged approximately 40% more than consumption during the summer months. This seasonal trend is reflected in the chart below, which shows annual U.S. natural gas consumption by sector for the period January 2004 to October 2009.

Annual U.S. Natural Gas Consumption by Sector

Note: Supply includes lower 48 state production, net pipeline imports, and LNG imports.

Source: Derived from EIA data Updated March 5, 2010

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Looking forward, publications by the EIA and other industry sources forecast that long-term demand for natural gas will continue to grow and that the historical trend of growth in natural gas demand from seasonal and weather-sensitive consumption sectors will also continue. Among the various factors that we believe support these forecasts are (i) expectations of continued growth in the U.S. gross domestic product, which has a significant influence on long-term growth in natural gas demand, (ii) an increased likelihood that regulatory and legislative initiatives regarding U.S. carbon policy will drive greater demand for cleaner burning fuels like natural gas, (iii) increasing acceptance of the view that fossil fuels will continue to provide the vast majority of total energy used in the U.S. for the foreseeable future and that natural gas is a clean and abundant domestic fuel source that can lead to greater energy independence for the U.S. by reducing its dependence on imported petroleum, and (iv) continued growth in electricity generation from intermittent renewable energy sources, primarily wind and solar energy, for which natural-gas fired generation is a logical back-up power supply source.

Natural Gas Supply. The extent to which natural gas supplies are available on a seasonal or shorter-term basis to meet the demand for natural gas consumption directly impacts the demand for storage; however, storage capacity is required in both an oversupplied and an undersupplied natural gas market. In market conditions where there is insufficient domestic production and import supply to meet demand, natural gas must be withdrawn from storage to balance the market. Conversely, in market conditions where there is excess domestic production and import supply relative to demand, natural gas must be injected into storage to balance the market or domestic production and imports must be reduced.

For the foreseeable future, we believe there will be ample supplies of natural gas from a combination of domestic production, pipeline imports and waterborne imports of LNG. We also believe, however, that it is difficult to predict the extent to which domestic production from unconventional shale resources and LNG imports will increase or decrease and that this source of supply uncertainty adds an element of volatility to natural gas markets that will drive greater demand for storage services, especially from well-positioned, high-performance facilities that can provide customers with access to both LNG imports and shale production.

Near-Term Domestic Production Growth. For the majority of the last decade, domestic production has been relatively flat and has failed to keep pace with domestic consumption. Over the past few years, however, domestic production has been growing, primarily due to increases in production from developing shale resource plays. According to EIA data, during the two-year period from January 1, 2007 through December 31, 2008 domestic production of natural gas increased by an average of approximately 5% per annum and estimates of proved natural gas reserves increased by an average of approximately 7.6% per annum, in each case largely due to continued development of shale resources. Beginning in 2007, leasing and development activities increased in a number of new shale resource plays, which in 2009 caused the EIA to significantly increase its outlook for domestic natural gas production. Notably, the typical production profile for shale production is short lived with initial high levels of production and steep declines thereafter. For this reason, and because producing gas from shale formations is generally more complex and expensive than conventional onshore production, it is difficult to predict future shale resource production levels with certainty.

LNG Supplies. In addition to the emergence of domestic shale plays as a significant supply source, over the past several years, the U.S. has developed significant infrastructure for the import of LNG. In recent years, U.S. and Canadian LNG imports have averaged an aggregate of approximately 1 to 3 Bcf per day, while the total LNG import capacity of U.S. and Canadian infrastructure is approximately 16 Bcf per day. In addition, incremental U.S. and Canadian capacity is scheduled to come online over the next few years.

Supply Variability and Uncertainty. We believe this source of supply uncertainty and potential variability related to both domestic production and LNG imports will continue for the foreseeable future, and will contribute to the volatility of natural gas markets and support continued demand for storage capacity, especially high-deliverability storage that provides customers with greater flexibility to access both domestic production from shale resources and LNG imports.

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Supply of Storage Capacity. An important factor in determining the value of storage is whether there is a surplus or shortfall of storage capacity relative to the overall demand for storage services in a given market area. In general, on a relative basis, storage values will be lower in markets that are oversupplied with storage than in markets where storage capacity is in short supply. The extent to which markets are oversupplied or undersupplied will fluctuate in response to significant variations in natural gas supply and demand.

The EIA reports two measures of aggregate peak storage capacity for the U.S.: working gas design capacity and demonstrated non-coincidental peak storage capacity. Working gas design capacity is a measure based on the design capabilities of all U.S. storage facilities whereas demonstrated peak capacity is based on the non-coincidental peak storage volumes for each of these facilities over the last five years (i.e., the sum of maximum volumes stored at each facility at any time within the five-year period). According to the EIA, the aggregate peak working gas capacity of the U.S. underground natural gas storage market is approximately 4.3 Tcf using the design capacity methodology and 3.9 Tcf using the non-coincidental peak storage methodology. A comparison of actual peak storage inventory levels to working gas design capacity and demonstrated non-coincidental peak storage capacity since 2005 suggests that since 2005, peak storage utilization as a percentage of peak storage capacity has increased using both EIA measures of aggregate peak storage capacity. Utilization has increased from 82% to 89% using the working gas design capacity measure and from 91% to 99% using the demonstrated non-coincidental peak storage capacity measure. While both measures have merits, we believe the non-coincidental peak storage measure is a better directional indicator of true useable storage capacity due to the fact that working gas design capacity is based on design parameters and does not take into account operational, logistical and other practical constraints. The graph below illustrates the relationship between actual peak storage inventory levels and non-coincidental peak storage levels between 2005 and 2009 based on EIA data, and also reflects the 3.84 Tcf record level of working gas stored in underground storage facilities on November 27, 2009.

U.S. Working Gas Capacity (Non-Coincidental Peak Levels and Design Capacity) vs. Peak Storage Inventory Levels (2005-2009)

Source: derived from EIA data

Although the above chart suggests that storage utilization is high and the current market for storage capacity may be approaching an undersupplied state, future market conditions will be determined both by the future demand for storage as well as the net amount of storage capacity that is added in future years. From a storage operator s perspective, an over-build of storage capacity would reduce storage values by putting downward pressure on the rates that storage providers are able to charge for new contracts on uncontracted capacity and renewal contracts with existing customers whose contracts are approaching expiration. Conversely, a continuation of an undersupplied storage market would imply higher values and rates for new contracts and renewals of expiring contracts.

Following the FERC s change in policies and practices with respect to natural gas storage in the late 1990s and early 2000s, there has been a significant increase in the number of permits requested and issued for new storage facilities. For example, according to FERC data, during the period from January 2000 through January 2010, permits have been issued by the FERC for new interstate gas storage facilities or expansions in the Gulf Coast (excluding intrastate facilities and FERC pre-filings for additional storage capacity) representing aggregate additional working gas capacity of approximately 576 Bcf. However, through January 2010, based on our review of publicly available FERC filings and other publicly available data, we estimate that only approximately 153 Bcf, or 27%, of such permitted capacity has been placed in service, which leaves approximately 423 Bcf of permitted Gulf Coast capacity that has not yet been placed in service.

While it is difficult to predict when, and how much of, such permitted but not yet in service capacity will ultimately be placed in service, based on our review of publicly available FERC filings and other publicly available data, a significant number of these Gulf Coast projects have experienced delays and some of them have been abandoned. These delays and abandonments are due to a variety of factors, including geological issues, permitting delays, financing issues, landowner and public relations issues, construction issues and operating challenges.

We believe that these types of challenges will continue to affect storage capacity development in the U.S. and will result in a number of new projects being placed in service later than initially forecast or at lesser volumes of working capacity than the backlog of permitted projects indicates. As a result, we believe there will continue to be market demand for the services we provide.

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BUSINESS

Overview

We are a fee-based, growth-oriented Delaware limited partnership formed by Plains All American to own, operate and grow the natural gas storage business that PAA acquired in 2005 and has continuously operated since that time. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. We currently own and operate two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 Bcf and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. We also lease storage capacity and pipeline transportation capacity from third parties from time to time in order to increase our operational flexibility and enhance the services we offer our customers. As of April 1, 2010, we had 5.3 Bcf of storage capacity under lease from third parties and had secured the right to 286 MMcf per day of firm transportation service on various pipelines. Substantially all of our revenues are derived from the provision of firm storage services under multi-year, fee-based contracts.

Our business has expanded rapidly since its inception in 2005, primarily through organic growth initiatives. We have grown our storage capacity from 20 Bcf as of December 31, 2005 to 40 Bcf as of December 31, 2009, and we expect this growth to continue at a rapid pace as we complete our planned expansions over the next several years. Our expansion plans include an additional 31 Bcf of working gas storage capacity, 28 Bcf of which we expect to place into service by mid-2012, including 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. Our target is to increase our total capacity to 68 Bcf by mid-2012, representing a 70% increase in storage capacity from year-end 2009 levels. Through our current assets and proposed expansions, we believe we are well-positioned to benefit from the anticipated long-term growth in demand for natural gas storage capacity and services in North America.

Our Assets

We own 100% of the Pine Prairie facility, which is a recently constructed, high-deliverability salt-cavern natural gas storage complex located in Evangeline Parish, Louisiana, and 100% of the Bluewater facility, which is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. The following table contains certain information regarding our Pine Prairie and Bluewater storage facilities:

Facility Name and Type	Working Gas Capacity (Bcf)	Peak Injection Rate (Bcf/d)	Peak Withdrawal Rate (Bcf/d)	Compression (Horsepower)
Pine Prairie (salt-cavern)				
Existing facility	14	1.2	2.4	32,000
Planned expansion	31(1)	1.2(2)	0.8(2)	56,250(3)
Subtotal:	45	2.4	3.2	88,250
Bluewater (depleted reservoir)				
Existing facility	26	0.5	0.8	13,350
Planned expansion	2(4)			

Subtotal:	28	0.5	0.8	13,350
Total (both facilities)	73	2.9	4.0	101,600

(1) We expect to place 10 Bcf into service in the second quarter of 2010, 18 Bcf by mid-2012 and the final 3 Bcf will be added ratably through 2016.

(2) We expect to complete these expansions of peak injection and withdrawal capabilities by mid-2011.

(3) Of this aggregate expected increase in compression, 16,000 horsepower is on location with installation targeted for April 2010. With respect to the remaining compression capacity, we expect 23,000 horsepower to be in place by mid-2011, and an additional 17,250 horsepower to be in place by mid-2012.

(4) We expect to place this expansion in working gas capacity into service ratably over a 10-year period beginning in 2011 in connection with a planned liquids removal project.

Pine Prairie. As a strategically-located, high-deliverability storage facility, Pine Prairie has attracted a diverse group of customers, including utilities, pipelines, producers, power generators, marketers and LNG importers, whose storage needs include both traditional seasonal storage services and short-term storage services. Pine Prairie is strategically positioned relative to several major market hubs, including:

- the Henry Hub, which is the delivery point for NYMEX natural gas futures contracts and is located approximately 50 miles southeast of Pine Prairie;

- the Carthage Hub in east Texas, which is located approximately 150 miles northwest of Pine Prairie; and

- the Perryville Hub in north Louisiana, which is located approximately 130 miles north of Pine Prairie.

Pine Prairie s pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that service both conventional and unconventional natural gas production in Texas and Louisiana, including production from existing and emerging shale plays, as well as Gulf of Mexico production and LNG imports. These interconnects also provide direct or indirect access to each of the market hubs described above and to consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast regions of the United States. This interconnectivity, combined with existing compression capacity and approximately 50 MMcf per day of leased third-party pipeline transportation capacity as of December 31, 2009, gives Pine Prairie the operational flexibility to receive from and deliver to multiple pipelines simultaneously.

Pine Prairie has a total current working gas storage capacity of 14 Bcf in two caverns, and planned expansions that will increase Pine Prairie s total capacity to 42 Bcf by mid-2012 and 45 Bcf by mid-2016 (see table above). Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf.

Bluewater. Bluewater is located in the State of Michigan, which contains more underground natural gas storage capacity than any other state in the U.S. according to EIA data, and primarily services seasonal storage needs throughout the Midwestern and Northeastern portions of the U.S. and the Southeastern portion of Canada. Accordingly, Bluewater s customers consist primarily of pipelines, utilities and marketers seeking seasonal storage services. Bluewater s 30-mile, 20-inch diameter pipeline header system is supported by 13,350 horsepower of compression and connects with three interstate and three natural gas utility pipelines that provide access to the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. These interconnects also provide access to natural gas utilities that serve local markets in Michigan and Ontario.

As indicated in the table above, Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and we expect to increase Bluewater s working gas capacity by 2 Bcf ratably over a 10-year period beginning in 2011 as a result of a planned liquids removal project. Bluewater also leases third-party storage capacity and pipeline transportation capacity from time to time to increase its operational flexibility and enhance its service offerings. As of April 1, 2010, we had leased approximately 5.3 Bcf of additional capacity at third-party natural gas storage facilities as well as 236 MMcf per day of related pipeline transportation capacity.

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Our Operations

We provide natural gas storage services to a broad mix of customers, including local gas distribution companies, or LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. Our storage rates are regulated under Federal Energy Regulatory Commission, or FERC, rate-making policies, which currently permit our facilities to charge market-based rates for our services.

We generate revenue almost exclusively through the provision of fee-based gas storage services to our customers. For the year ended December 31, 2009, approximately 99% of our total revenue was derived from fee-based storage activities, with the remaining approximately 1% primarily attributable to the sale of liquid hydrocarbons incidentally produced in connection with the operation of our depleted reservoir storage facilities at Bluewater as well as other fuel and derivative related net gains and losses. Our revenues from fee-based gas storage services are derived from both firm storage services and hub services.

> *Firm Storage Services.* Firm storage services include (i) storage services pursuant to which customers receive the assured or firm right to store gas in our facilities over a multi-year period and (ii) seasonal park and loan services pursuant to which customers receive the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis. Under our firm storage contracts, our customers are obligated to pay us fixed monthly capacity reservation fees, which are owed to us regardless of the actual storage capacity utilized. At Pine Prairie, our firm storage contracts typically have terms of 3 to 5 years, while at Bluewater terms generally range from 1 to 3 years. As of April 1, 2010, the weighted average remaining tenor of our existing portfolio of firm storage contracts is approximately 3.7 years at Pine Prairie and approximately 2.2 years at Bluewater. Under our firm storage contracts, we also typically collect a cycling fee based on the volume of natural gas nominated for injection and/or withdrawal and retain a small portion of natural gas nominated for injection as compensation for our fuel use. For the year ended December 31, 2009, approximately 92% of our total revenue was derived from firm storage services.

> *Hub Services.* We also generate revenue from the provision of hub services at our facilities. Hub services include (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) non-seasonal park and loan services and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from, our facilities. For the year ended December 31, 2009, approximately 7% of our total revenue was derived from hub services.

We believe that the high percentage of our baseline cash flow derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers stabilizes our cash flow profile and substantially mitigates the risk to us of significant negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. For additional information about our contracts, please read Business Contracts.

Our Business Strategy

Our principal business strategy is to capitalize on the anticipated long-term growth in demand for natural gas storage services in North America by owning and operating high-quality natural gas storage facilities and providing our current and future customers reliable, competitive and flexible natural gas storage and related services. In executing this strategy, we intend to expand the scope and scale of our business, grow our earnings and cash flow and increase the amount of cash distributions we make to our unitholders over time. Our plan for executing this strategy includes the following key components:

Optimizing our existing natural gas storage facilities. We are constantly seeking to optimize the performance and profitability of our existing natural gas storage facilities. Our primary commercial objective is to generate a significant portion of our revenues by committing a high percentage of our storage capacity under multi-year firm storage contracts at attractive rates. As of April 1, 2010, approximately 96% of our owned and leased total working gas capacity, which includes the 10 Bcf of additional capacity expected to be placed into service during the second quarter of 2010, was committed under our existing portfolio of firm storage contracts with a weighted average remaining tenor of approximately 3.7 years at Pine Prairie and approximately 2.2 years at Bluewater. We also provide our customers with a variety of hub services that are designed to accommodate customer needs, maximize the utilization of our assets and optimize our earnings and cash flow. For example:

If firm storage customers are not utilizing all of their firm capacity, we can offer such capacity to other customers on a short-term, interruptible basis, earning fees to the extent our capacity is actually utilized.

We offer various hub services, pursuant to which we earn fees for (i) allowing customers to park their gas in our facilities on a short-term basis, (ii) loaning gas to customers for relatively short periods of time and (iii) providing wheeling and balancing services to customers through the use of our header system.

Operationally, we seek to optimize our profitability by executing various initiatives that increase our efficiency, reliability and flexibility. For example:

Daily we manage the gas flows through our facilities to reduce our overall costs and optimize our use of compression. This is accomplished by aggregating and offsetting customer nominations to reduce required physical flows, scheduling our wheeling services to take advantage of pressure differentials across our system and sequencing our gas movements to increase the efficiency of compressor usage.

In 2009 we installed back-up generators that enable us to run our gas handling facility and pipeline interconnects at Pine Prairie in the event of a power interruption.

Subject to receipt of applicable approvals, our planned expansion to five caverns at Pine Prairie will include electric compression, which will diversify our existing portfolio of natural-gas fired compression and provide us with the flexibility to run more efficiently.

Organically expanding our existing natural gas storage facilities. Our existing assets enable us to expand our storage capacity on what we believe to be attractive economic terms. Our current expansion plans include the addition of 31 Bcf of working gas storage capacity at our Pine Prairie facility, 28 Bcf of which we expect to place into service by mid-2012, including 10 Bcf of new capacity that is substantially complete and that we currently expect to place into service during the second quarter of 2010. We have received all applicable federal, state and local approvals required to construct these expansions (including FERC and Louisiana Department of Natural Resources) and, when complete, we will have five salt caverns in service and 45 Bcf of working gas storage capacity at Pine Prairie. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf. In addition, we are currently pursuing a liquids removal project to expand our storage capacity at our Bluewater facility by 2 Bcf ratably over a 10-year period beginning in 2011.

Pursuing strategic and accretive acquisition or development projects. We continually evaluate opportunities to acquire or develop new natural gas storage facilities in our existing and new markets. In general, we are seeking acquisition or development opportunities that will be accretive (or result in an increase in distributable cash flow on a per unit basis) and that will add natural gas storage assets or facilities that either complement our existing assets or strategically enhance our overall business by facilitating our entry into a desirable new market, diversifying our customer base or positioning us for future growth. Working with PAA, we are currently involved in discussions and, in certain cases negotiations, with a number of potential sellers regarding the purchase of natural gas storage assets. Although there can be no assurances that viable acquisition or development opportunities will continue to be available to us or that we will ultimately be able to consummate any of the transactions currently being considered, we believe the combination of strong long-term fundamentals for natural gas demand and storage services coupled with the fragmented nature of the gas storage business should result in a variety of acquisition and/or development opportunities for us to consider. In addition, over time and working in conjunction with PAA, we intend to evaluate opportunities to acquire or develop other natural gas-related assets or businesses that complement our natural gas storage business and allow us to leverage our asset base and industry experience.

Leasing storage capacity and transportation services from third parties to enhance operational flexibility. In order to supplement our owned storage capacity, increase our operating flexibility, enhance the services that we are capable of offering to our customers and optimize the commercial performance of our assets, we periodically lease storage and/or transportation capacity from third parties. As of April 1, 2010, we had 5.3 Bcf of storage capacity under lease from third parties and had secured the right to 286 MMcf per day of firm transportation service on various pipelines.

Utilizing a portion of our owned and leased storage capacity to enhance our commercial management activities. Similar to the business model successfully employed by PAA, and without altering our basic commercial strategy of committing a high percentage of our storage capacity under multi-year firm storage contracts at attractive rates, during 2010 we intend to establish a dedicated commercial marketing group that will capture short-term market opportunities by utilizing a portion of our owned or leased storage capacity for our own account and engaging in related commercial marketing activities. Consistent with PAA s experience marketing crude oil and refined products, we believe a dedicated commercial marketing group that has a consistent presence in our markets will enhance our ability to properly price our storage and hub service offerings and will increase our earnings by capitalizing on volatility and inefficiencies in the natural gas markets. We will conduct these commercial activities within pre-defined risk parameters, and our general policy will be (i) to purchase natural gas only in situations where we have a market for such gas, (ii) to utilize physical natural gas inventory and financial derivatives to manage and optimize seasonal and spread risks inherent in our operations and commercial management activities and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flow and (iii) not to acquire or hold natural gas, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes.

Our Financial Strategy

Important factors to successfully grow our business will be our ability to maintain a competitive cost of capital and sufficient access to the capital markets. These factors will be significantly influenced by our ability to grow our distribution to unitholders, maintain a solid credit profile and ultimately achieve and maintain an investment-grade credit rating.

Targeted Credit Profile. We have targeted a general credit profile that has the following attributes:

a long-term debt-to-total capitalization ratio of 40% or less;

an average long-term debt-to-Adjusted EBITDA multiple of approximately 3.5x (Adjusted EBITDA is earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, gains and losses from derivative activities and selected items that are generally unusual or non-recurring); and

an average Adjusted EBITDA-to-interest coverage multiple of approximately 3.3x or better.

When considered together with what we believe to be the relatively low risk profile of our business, we believe this credit profile is consistent with an investment grade credit rating. In combination with our intent to maintain a high percentage of storage capacity under multi-year contracts, this credit profile should also provide flexibility if storage markets become oversupplied and position us to take advantage of attractive acquisition opportunities.

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In order for us to maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for expansion and acquisition projects through a combination of equity capital and cash flow in excess of distributions. In connection with this offering, we entered into a new $400 million revolving credit facility. We believe we will be able to fund up to the first $250 million of acquisitions or expansion projects primarily through borrowings under this credit facility or other sources and remain in compliance with our targeted credit profile.

From time to time, we may be outside the parameters of our targeted credit profile due to timing issues related to the initial funding of certain capital expenditures or acquisitions with debt or delays in realizing increases in Adjusted EBITDA, synergies or other benefits from expansion and/or acquisition projects.

Credit Rating. We have not applied for a credit rating from any credit rating agency, nor to our knowledge has any such credit rating been assigned. Additionally, we do not currently intend to apply for a credit rating until such time as we expect to access the public debt capital markets. If and when we seek a credit rating, our credit rating may be positively or negatively impacted by the leverage and credit rating of PAA. In addition, while we believe our targeted credit profile is consistent with an investment grade rating, we can provide no assurance in this regard. See Risk Factors The credit and risk profile of our general partner and its owner, PAA, could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

As of April 1, 2010, the senior unsecured ratings of PAA with Standard & Poor s Ratings Services and Moody s Investors Service were BBB-, stable outlook, and Baa3, stable outlook, respectively.

Our Competitive Strengths

We believe that the following competitive strengths will position us to successfully execute our principal business strategy:

Our natural gas storage assets are strategically located and operationally flexible. Our Pine Prairie facility is strategically positioned relative to several major market hubs, including the Henry Hub, the Carthage Hub, and the Perryville Hub and is located approximately 80 miles inland from the Gulf Coast shoreline, a feature that minimizes Pine Prairie s exposure to operational disruptions from hurricanes or other severe weather affecting the Gulf of Mexico region. Pine Prairie s pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, is directly connected to eight large-diameter interstate pipelines through nine interconnects that enable it to serve a variety of major producing regions, LNG importers and the primary consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast. This interconnectivity, combined with existing compression capacity and approximately 50 MMcf per day of leased third-party pipeline transportation capacity as of December 31, 2009, gives Pine Prairie the operational flexibility to receive from and deliver to multiple pipelines simultaneously.

Pine Prairie s operational flexibility enables it to partially fill or deplete, or cycle, its storage caverns multiple times per year. This allows Pine Prairie to offer a premium service of cycling or turning contracted storage volume up to twelve times per year, providing Pine Prairie customers with additional operating and financial flexibility. The significant operational flexibility of the Pine Prairie facility also creates more opportunities for us to provide our customers with hub services, such as interruptible storage, park and loan, balancing and wheeling services.

Our Bluewater natural gas storage complex is strategically positioned to access the major market hubs of Chicago, Illinois and Dawn, Ontario, which supply natural gas to eastern Ontario and the northeastern United States. Bluewater s 30-mile pipeline header system connects the facility to three interstate and three natural gas utility pipelines and provide access to natural gas utilities that serve local markets in Michigan and Ontario.

Collectively, our facilities have aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. Upon the completion of current expansion activities, these capabilities will increase to 2.9 Bcf per day of peak rate injection capability and 4.0 Bcf per day of peak rate withdrawal capability.

Our business generates relatively stable and predictable cash flow. Given the high percentage of our cash flow that is derived from fixed-capacity reservation fees under multi-year contracts with a diverse portfolio of customers, our baseline cash flow profile is relatively stable and predictable, which we believe significantly mitigates the risk to us of negative cash flow fluctuations caused by changing supply and demand conditions and other market factors. For the twelve-month period that ended on December 31, 2009, approximately 92% of our total revenue was derived from the provision of firm storage services, and as of April 1, 2010, the weighted average remaining life of our existing portfolio of firm storage contracts is approximately 3.7 years at our Pine Prairie facility and approximately 2.2 years at our Bluewater facility. In addition, we do not take title to the natural gas that we store for our customers and, accordingly, are not exposed to commodity price fluctuations on the gas that is stored in our facilities by our customers. Except for the base gas we purchase and use in our facilities, which we consider to be a long-term asset, and volume and pricing variations related to small amounts of natural gas we are entitled to retain from our customers as compensation for our fuel costs, our current and planned business strategies are designed to minimize our exposure to fluctuations in the outright price of natural gas.

Our Pine Prairie storage facility has the ability to be significantly expanded at competitive costs and with a relatively high degree of schedule certainty. We own and/or lease 320 acres of land on the salt dome that underlies Pine Prairie. Our existing facilities and planned expansions through 2012 to five caverns will utilize only approximately 120 of these acres. Subject to market demand, project execution, sufficient pipeline capacity, available financing and receipt of future permits, we have the property rights and operational capacity to expand our Pine Prairie facility significantly beyond our current permitted capacity of 48 Bcf. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that Pine Prairie could support in excess of 15 salt caverns and an aggregate storage capacity of over 150 Bcf. In addition, because our existing infrastructure at Pine Prairie has been specifically designed to facilitate future expansion, we expect it to both reduce our overall capital costs per additional Bcf of storage capacity and shorten the length and enhance the predictability of our development cycle. Some of the specific aspects of our Pine Prairie facility that will facilitate incremental expansion are as follows:

Pine Prairie has been specifically designed solely for natural gas storage development, and we have customized the design and layout of the caverns so that (i) there is ample spacing between caverns and (ii) the caverns are optimally shaped for natural gas storage.

Pine Prairie has a solution mining facility (used to create salt-dome storage caverns) that is capable of leaching at an aggregate rate of 8,000 gallons of water per minute, a rate that we believe to be significantly higher than the rates at many competing facilities. This solution mining facility and supporting infrastructure provide us with the capability to simultaneously conduct leaching operations on new caverns, remove water from a recently completed cavern (called dewatering) and/or conduct fill/dewater operations on existing caverns (a process used to expand the capacity of an existing cavern through incremental leaching), subject to a maximum fluid handling capacity of 8,000 gallons per minute. For approximately six months during 2009, all three of these activities were conducted simultaneously on three cavern wells, achieving water handling rates of approximately 7,500 gallons per minute for extended periods of time.

The pipeline header system, pipeline interconnects and gas treating facilities at Pine Prairie are complete and have been designed to accommodate larger-scale future expansion. The pipeline header system, which includes an aggregate of 74 miles of 24-inch diameter pipe located within a 20-mile radius of Pine Prairie, can move volumes of gas through our facility at peak rates that comfortably exceed both our current peak gas storage withdrawal rate of 2.4 Bcf per day and our withdrawal rate of 3.2 Bcf per day after our planned expansions are completed.

We believe these features of our Pine Prairie facility, together with the significant hands-on experience that has been gained by our personnel while developing the first three caverns at Pine Prairie, provide us with the capability to (i) develop expansion capacity at costs that are competitive with or superior to expansion costs at other Gulf Coast facilities and substantially lower than greenfield development projects and (ii) place new caverns in service for existing and potential customers quickly and with a high degree of certainty regarding the projected in service dates.

We have the evaluation, integration and engineering skill sets in-house that are necessary to successfully pursue acquisition and expansion opportunities. We possess the in-house capabilities and expertise necessary to develop, construct, own, acquire and operate both depleted reservoir and salt-cavern storage capacity. We have been involved in substantially all aspects of the natural gas storage business since 2005 and our operational and management team has extensive energy industry and acquisition experience. In addition, from 1998 to 2009, PAA has (i) successfully acquired and integrated over $6 billion of acquisitions in over 50 separate transactions involving midstream energy assets, and (ii) executed organic growth and expansion projects with total capital expenditures of over $2.1 billion. We believe that the experience and skill sets of our collective management team provide us with a competitive advantage that enables us to appropriately identify, assess and evaluate the risks and opportunities that are likely to arise during the development and operational phases of potential gas storage acquisition and expansion opportunities.

We have the financial flexibility to pursue acquisition and expansion opportunities. At the closing of this offering, we expect to have approximately $200 million of borrowing capacity available to us under our revolving credit facility. We believe our borrowing capacity and our ability to access private and public debt and equity capital should provide us with the financial flexibility necessary to execute our growth and expansion strategy. Additionally, PAA may elect, but is not obligated, to provide us with financial support in connection with acquisitions or expansion capital projects in certain circumstances.

Our general partner has an experienced executive management team with specialized knowledge of natural gas storage and markets and whose interests are aligned with those of our unitholders. Our general partner has an executive management team that has extensive experience managing, operating, building, acquiring and integrating energy assets, including natural gas storage assets and other midstream energy assets. On average, the members of our general partner s executive management team have in excess of 20 years of energy industry experience. In addition, our general partner s executive management team includes a President and three Vice Presidents who are exclusively dedicated to and focused on the operation, management, development and expansion of our natural gas storage business. Through their indirect and direct interests in us, our general partner and PAA, our general partner s executive management team has a significant, vested interest in our continued success. We believe the experience of our general partner s executive management team and the experience and market presence of PAA, combined with our relationships with participants across the natural gas supply chain, provide us with extensive operational and commercial understanding of the physical North American natural gas market.

We believe these competitive strengths will aid our efforts to expand our presence in the natural gas storage sector.

Our Relationship with Plains All American Pipeline, L.P.

We believe one of our strengths is our relationship with Plains All American Pipeline, L.P., which, based on our review of publicly available data, is the fifth largest publicly traded master limited partnership as measured by equity market capitalization, which was approximately $8.0 billion as of April 29, 2010. Plains All American s common units trade on the New York Stock Exchange, or NYSE, under the ticker symbol PAA. In addition to its participation in the natural gas storage business through our partnership, PAA is engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. PAA s assets include approximately 17,000 miles of pipelines, 85 million barrels of storage capacity, and a significant fleet of trucks, trailers, tugs, barges and railcars. Through its transportation, storage and commercial activities, PAA physically handles approximately 3 million barrels per day of petroleum products.

PAA and its predecessors have been active participants in the hydrocarbon storage industry since the early 1990s. PAA has a long history of successfully expanding its energy infrastructure businesses through a combination of organic growth projects and complementary acquisitions. Since its initial public offering in 1998, PAA has grown its asset base from approximately $600 million to over $12 billion and increased the annualized distribution on its limited partner units by over 100%, from $1.80 per unit as of PAA s initial public offering to $3.74 per unit for the distribution declared to be paid in May 2010.

Our partnership will own all of the natural gas storage business and assets formerly owned by PAA and PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business. Upon completion of this offering, as the ultimate owner of our 2.0% general partner interest, all of our incentive distribution rights and an approximate 77.9% limited partner interest in us (including common units, Series A subordinated units and Series B subordinated units), PAA will have a significant economic stake in us and a commensurate incentive to promote and support the successful execution of our growth plan and strategy.

We will also enter into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we will agree upon certain aspects of our relationship with them, including the provision by PAA s general partner to us of certain general and administrative services and employees, our agreement to reimburse PAA s general partner for the cost of such services and employees, certain indemnification obligations, the use by us of the name PAA and related marks, and other matters. Please read Certain Relationships and Related Transactions Agreements Governing the Transactions Omnibus Agreement.

We believe PAA s significant presence in the energy sector, its successful track record of growth and its significant investment in, and sponsorship and support of, us will enhance our ability to grow our business. While we believe this relationship with PAA is a significant positive attribute, it may also be a source of conflicts. For example, PAA is not restricted in its ability to compete with us. Please read Conflicts of Interest and Fiduciary Duties.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of natural gas storage assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as auction processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations.

In connection with our acquisition activities, we routinely incur evaluation and due diligence costs, which are expensed as incurred. In addition to the in-house costs of our personnel and ancillary overhead expenditures allocated to us by our general partner for time devoted to evaluating acquisition opportunities which can be substantial, we also budget approximately $250,000 per year associated with third party evaluation or due diligence costs for transactions that are assumed not to be consummated.

Working with PAA, we are currently involved in discussions and, in certain cases, negotiations, with a number of potential sellers regarding the purchase of natural gas storage assets. Certain of these discussions are more advanced than others, but past experience has demonstrated that any of these discussions and negotiations could advance or terminate in a short period of time. However, regardless of their outcome, because of the current increased level of activity, third party expenses may exceed our typical budgeted levels in the near term. Additionally, certain of the opportunities under evaluation are of a size that would likely involve PAA s assistance with respect to financing or jointly purchasing such assets. See Management s Discussion and Analysis of Financial Condition and Results of

Operations   Liquidity and Capital Resources   Potential PAA Financial Support.   We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us. See

Risk Factors If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

Customers

Pine Prairie and Bluewater collectively provide storage services to a broad mix of customers including LDCs, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. LDCs use storage services for seasonal balancing, to meet peak day deliveries and ensure reliability. Pipelines use storage services to manage short-term operational balancing requirements. Power generators, marketers and producers generally use storage services for short-term balancing, to manage risk and to take advantage of the pricing differential between near-term and long-term natural gas. LNG importers use storage to insure they have adequate storage capacity to accommodate imported LNG cargoes.

As of December 31, 2009, Pine Prairie had 11 customers with firm storage contracts and 45 customers with hub services contracts and Bluewater had 30 customers with firm storage contracts and 46 customers with hub services contracts. For the year ended December 31, 2009, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 17% and 13% of our revenues, respectively.

Contracts

Pine Prairie and Bluewater contract with their customers to provide firm storage services and hub services. Under firm storage contracts, in exchange for an assured amount of storage capacity for an agreed period of time, customers pay a fixed monthly capacity reservation fee that is payable regardless of the actual amount of storage capacity utilized. Under these contracts, Pine Prairie and Bluewater also typically collect a cycling fee based on the volume of natural gas nominated for injection and/or withdrawal and retain a small portion of natural gas nominated by their customers for injection as compensation for their fuel costs. The firm storage contracts at Pine Prairie and Bluewater typically have terms of 3 to 5 years, and 1 to 3 years, respectively. Our general contracting philosophy at both Pine Prairie and Bluewater is to commit a high percentage of our available working gas capacity to firm storage contracts at attractive rates, while simultaneously contracting for hub services to increase asset utilization and capture margin based on market conditions. As of April 1, 2010, the weighted average remaining tenor of our existing portfolio of firm storage contracts is approximately 3.7 years at Pine Prairie and approximately 2.2 years at Bluewater.

Despite an increase in the number of competitors in recent years, especially in the markets served by our Pine Prairie facility, we have been able to contract all of our available storage capacity at acceptable rates. As an example, in June 2009 Pine Prairie concluded an open season pursuant to which it requested non-binding bids for 2 Bcf of capacity starting April 1, 2010. In response to such request, Pine Prairie received 26 individual bids for an aggregate capacity of over 29 Bcf with initial contract terms ranging from 3 to 5 years. We also concluded an open season at Bluewater in July of 2009 pursuant to which we requested nonbinding bids for 2.5 Bcf of capacity starting April 1, 2010. In response to such request, Bluewater received 22 individual bids for an aggregate capacity of 31 Bcf with initial contract terms ranging generally from 1 to 5 years. We believe our contracting success at Pine Prairie and Bluewater is due to various positive attributes of such storage facilities, including their favorable access to neighboring pipeline systems and the flexibility and reliability of their service offerings.

Pine Prairie and Bluewater also contract with their customers to provide hub services. Hub services include (i) interruptible storage services pursuant to which customers do not receive any assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) non-seasonal park and loan services, pursuant to which customers pay fees for the right to store gas in our facilities, and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from our facilities.

For the year ended December 31, 2009, approximately 92% of our total revenues were derived from the provisions of firm storage services and approximately 7% were derived from the provision of hub services.

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Competition

The principal elements of competition among storage facilities are rates, terms of service, types of service, supply and market access, and flexibility and reliability of service. An increase in competition in our markets could arise from new ventures or expanded operations from existing competitors.

Pine Prairie competes with several regional high-deliverability storage facilities along the Gulf Coast as well as the storage services offered by interstate and intrastate pipelines that serve the same markets as Pine Prairie. Pine Prairie s regional competitors include the Egan storage facility owned by Market Hub Partners, which is controlled by Spectra Energy Corp., the Southern Pines storage facility owned by SGR Holdings, the Bobcat storage facility owned by Haddington Ventures and GE Capital, the Petal storage facility owned by Enterprise Products Partners, L.P., the Jefferson Island storage facility owned by AGL Resources and the Bay Gas storage facility owned by Sempra Energy. We anticipate that growing demand for natural gas storage along the Gulf Coast will be met with increasing storage capacity, either through the expansion of existing facilities or the construction of new storage facilities. For example, we expect additional regional competition from proposed storage facilities or expansions at the Southern Pines storage facility, the Bobcat storage facility, the Petal storage facility, the Perryville Gas Storage facility owned by Cardinal Gas Storage Partners, the Leaf River storage facility owned by NGS Energy, L.P. and the Mississippi Hub storage facility owned by Sempra Energy.

Bluewater competes with several Midwest utility and pipeline storage providers. Bluewater s main regional competitors include DTE Energy, a Michigan gas and electric utility, ANR Pipeline Company, a major interstate pipeline company that is a subsidiary of TransCanada, and Union Gas Limited, a subsidiary of Spectra Energy engaged in the natural gas storage, transmission and distribution business. We anticipate growing demand for natural gas storage in the markets served by Bluewater as well as increased competition from existing regional competitors.

Regulation

Our operations are subject to extensive laws and regulations. We are subject to regulatory oversight by numerous federal, state, and local regulatory agencies, many of which are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas storage and pipeline industry, related businesses and individual participants. The failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. Except for certain exemptions that apply to smaller companies, however, we do not believe that we are affected by these laws and regulations in a significantly different manner than are our competitors.

Following is a discussion of certain laws and regulations affecting us. However, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Our natural gas storage assets are subject to several kinds of regulation. Our historical and projected operating costs reflect the recurring costs resulting from compliance with these regulations, and we do not anticipate material expenditures in excess of these amounts in the absence of future acquisitions or changes in regulation, or discovery of existing but unknown compliance issues. The following is a summary of the kinds of regulation that may impact our operations.

Natural Gas Storage Regulation

Interstate Regulation. Our natural gas storage facilities, Pine Prairie and Bluewater, are both classified as natural-gas companies under the NGA, and are therefore subject to regulation by the FERC. The NGA requires that tariff rates for gas storage facilities be just and reasonable and non-discriminatory. The FERC has authority to regulate rates and charges for natural gas transported and stored in U.S. interstate commerce or sold by a natural gas company in interstate commerce for resale. The FERC has granted the Pine Prairie and Bluewater natural gas storage facilities market-based rate authority. Market-based rate authorization allows

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Pine Prairie and Bluewater to negotiate rates with individual customers based on market demand, which Pine Prairie and Bluewater then make public via postings on their respective websites.

The FERC also has authority over the construction and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. In addition, the FERC s authority extends to maintenance of accounts and records, terms and conditions of service, depreciation and amortization policies, acquisition and disposition of facilities, initiation and discontinuation of services, imposition of creditworthiness and credit support requirements applicable to customers and relationships among pipelines and storage companies and certain affiliates.

Standards of Conduct for Transmission Providers. Historically, the FERC s standards of conduct regulations (now vacated) generally restricted access to U.S. interstate natural gas storage customer data by marketing and other energy affiliates, and placed certain conditions on services provided by U.S. storage facility operators to their affiliated gas marketing entities. The standards of conduct did not apply, however, to natural gas storage providers authorized to charge market-based rates that (i) were not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline and (ii) had no exclusive franchise area, no captive ratepayers, and no market power. The FERC found that Pine Prairie qualified for this exemption from the standards of conduct in January 2006 and Bluewater qualified for this exemption in October 2006.

In November 2006, the D.C. Circuit vacated the standards of conduct regulations with respect to natural gas pipelines and storage companies, and remanded the matter to the FERC. Following a notice of proposed rulemaking, in October 2008, the FERC issued revised Standards of Conduct for Transmission Providers (Standards of Conduct). The Standards of Conduct continue to exempt natural gas storage providers like Pine Prairie and Bluewater. The FERC has since issued two Orders on Rehearing and Clarification in October and November 2009. However, requests for rehearing of the October 2009 order are pending with the FERC. Accordingly, there may be further modifications to the Standards of Conduct upon rehearing.

Natural Gas Price Transparency. In April 2007, the FERC issued a notice of proposed rulemaking (NOPR) regarding price transparency provisions of the NGA and the EPAct 2005. In the notice, the FERC proposed to revise its regulations to, among other things, require that buyers and sellers of more than a de minimis volume of natural gas report annual numbers and volumes of relevant transactions to the FERC. In December 2007, the FERC issued Order No. 704 implementing the annual reporting provisions of the NOPR with minimal changes to the original proposal. The order became effective in February 2008. Pine Prairie and Bluewater are subject to these annual reporting requirements.

In November 2008, the FERC issued a final rule that requires interstate pipelines and certain non-interstate facilities to post certain daily capacity and volume information. The rule extends to storage facilities (such as Bluewater) that provide no-notice service. The rule has been appealed, but pending the results of that appeal, Bluewater will be subject to a requirement to post volumes with respect to no-notice service flows at each receipt and delivery point.

Energy Policy Act of 2005. Under the EPAct 2005 and related regulations, it is unlawful in connection with the purchase or sale of natural gas or transportation services subject to FERC jurisdiction to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1,000,000 per day per violation for violations occurring after August 8, 2005. The anti-manipulation rule and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority.

Other Proposed Regulation. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been heavily regulated. Accordingly, we cannot provide assurances that the less stringent and pro-competition regulatory approach recently pursued by the FERC and Congress will continue.

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Environmental Matters

General

Our natural gas storage operations are subject to stringent and complex federal, state, and local laws and regulations governing environmental protection, including air emissions, water quality, wastewater discharges, and solid waste management. Such laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, and other approvals. These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct certain activities, increases in operating expenses or curtailment of certain operations to limit or prevent the release of materials from our facilities, the incurrence of capital expenditures associated with the installation of pollution control equipment, and the imposition of substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil, and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations.

We believe that we are in substantial compliance with existing federal, state, and local environmental laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance of 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. The following is a discussion of some of the environmental laws and regulations that are applicable to our natural gas storage operations.

Waste Management

Our operations generate hazardous and non-hazardous solid wastes that are subject to the federal Resource Conservation and Recovery Act (RCRA) and comparable state laws and regulations, which impose detailed requirements for the handling, storage, treatment, and disposal of hazardous and non-hazardous solid wastes. For instance, RCRA prohibits the disposal of certain hazardous wastes on land without prior treatment. RCRA also requires waste generators subject to land disposal restrictions to provide notification of pre-treatment requirements to disposal facilities receiving such wastes. Generators of hazardous wastes must also comply with certain standards for the accumulation and storage of hazardous wastes and meet recordkeeping and reporting requirements applicable to hazardous waste storage and disposal activities.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA, also known as Superfund) and comparable state laws and regulations impose liability without regard to fault or the legality of the original conduct on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include current and prior owners or operators of the site where the release occurred and companies that disposed of, or arranged for the disposal of, hazardous substances found at offsite locations such as landfills. The CERCLA also authorizes the EPA and, in some instances, third parties, to respond to threats to public health or the environment and seek recovery of response costs from the class of responsible persons. Although natural gas is not classified as a hazardous substance under CERCLA, we may nonetheless handle hazardous substances within the meaning of CERCLA or similar state statutes in the course of our ordinary operations; as a result, we may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites where such hazardous substances have been released into the environment, natural resource damages, and the cost of certain health studies. Moreover, 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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Air Emissions

Our operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. These laws and regulations regulate the emission of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, and/or utilize specific emission control technologies to limit our emissions. To comply with, maintain, or obtain our air emissions operating permits, we may be required to incur certain capital expenditures in the future for the purchase and installation of air pollution control equipment. For example, we may be required to supplement or modify our air emission control equipment and strategies due to changes in state implementation plans for controlling air emissions or more stringent regulation of hazardous air pollutants.

Water Discharges

The Clean Water Act (CWA) and analogous state laws impose strict control of the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The CWA prohibits the discharge of pollutants into regulated waters, except in accordance with the terms of a permit issued by the EPA or analogous state agency. The CWA also regulates the discharge of storm water runoff from certain industrial facilities. Accordingly, some states require industrial facilities to obtain and maintain storm water discharge permits, which require monitoring and sampling of storm water runoff from such facilities.

Safe Drinking Water Act

As part of our operations, we employ underground injection wells to inject natural gas into our underground storage facilities. Such operations are subject to the Safe Drinking Water Act (SDWA) and analogous state laws, which regulate drinking water quality in the United States, including above ground and underground sources designated for actual or potential drinking water use. In particular, to protect underground sources of drinking water, the Underground Injection Control (UIC) Program of the SDWA regulates the construction, operation, maintenance, monitoring, testing, and closure of underground injection wells. The UIC Program also requires that all underground injection wells be authorized, either under the general rules of the UIC Program or through specific permits. In most jurisdictions, states have primary enforcement authority over the implementation of the UIC Program, including the issuance of permits.

Climate Change

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), which include carbon dioxide and methane, may be contributing to the warming of the Earth s atmosphere and other climatic changes. In response to such studies, the U.S. Congress is actively considering legislation to reduce anthropogenic GHG emissions. One bill recently approved by the U.S. House of Representatives, known as the American Clean Energy and Security Act of 2009, or ACESA, would require an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The U.S. Senate is currently considering its own climate change legislation, S. 1733, known as the Clean Energy Jobs and American Power Act, which requires a similar reduction in GHG emissions. Moreover, almost half of the states have taken legal measures to reduce GHG emissions. Both the state programs and proposed federal programs function primarily through the development of GHG emission inventories and/or a GHG cap and trade program. Most of these cap and trade programs work by requiring major sources of emissions (such as electric power plants) or major fuel producers (such as refineries and gas processing plants) to acquire and surrender emission allowances. The number of government-issued allowances under the cap, and correspondingly, the number of allowances available for trade, are reduced each year until the overall goal of GHG emission reductions is achieved.

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Depending on the scope of any particular GHG program, either at the state, regional, or federal level, we could be required to obtain and surrender allowances for GHG emissions statutorily attributed to our operations (e.g., emissions from compressor stations or the injection and withdrawal of natural gas). Although we would not be impacted to any greater degree than other similarly situated natural gas storage companies, a stringent GHG control program could have an adverse effect on our cost of doing business and reduce demand for the natural gas storage services we provide.

In addition, in December 2009, the EPA issued a final rule declaring that six GHGs, including carbon dioxide and methane, endanger both the public health and the public welfare of current and future generations. The issuance of this endangerment finding allows the EPA to begin regulating GHG emissions under existing provisions of the CAA. In late September and early October 2009, in anticipation of the issuance of the endangerment finding, the EPA officially proposed two sets of rules regarding possible future regulation of GHG emissions under the CAA, one that would regulate GHG emissions from motor vehicles and the other GHG emissions from large stationary sources such as power plants or industrial facilities. Although it may take EPA several years to adopt and impose regulations limiting GHG emissions, any limitation on such emissions from our equipment and operations could require us to incur costs to reduce the GHG emissions associated with our operations.

As part of the 2008 Consolidated Appropriations Act, the EPA was also required to issue a rule requiring mandatory reporting of GHG emissions above certain thresholds from all sectors of the U.S. economy. The proposed rule included GHG reporting requirements for oil and natural gas systems (Subpart W), including underground natural gas storage facilities, but the EPA received extensive comments to Subpart W relating to the reporting of fugitive and vented methane emissions from the oil and gas sector. As a result, when the final rule was promulgated in October 2009, the EPA decided not to issue Subpart W so that the agency could further consider alternative data collection procedures and methodologies. We anticipate that the EPA will re-issue a proposed rule regarding the reporting of GHG emissions from oil and natural gas systems sometime in 2010. Despite the delayed finalization of Subpart W, our compressors at the Pine Prairie facility may be subject to GHG reporting requirements under a separate section of the GHG reporting rule regulating General Stationary Fuel Combustion Sources. Any GHG reporting rule covering our facilities will require us to meet additional recordkeeping and reporting requirements, but we do not believe that any such future requirement will have a material adverse affect on our business, financial position, or results of operations.

Chemical Facility Anti-Terrorism Standards

The Department of Homeland Security Appropriation Act of 2007 required 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, deemed to present high levels of security risk. The DHS issued an interim final rule in April 2007 regarding risk-based performance standards under the act and, on November 20, 2007, issued Appendix A to the interim rule, which established chemicals of interest and their respective threshold quantities triggering compliance with the interim rule. Covered facilities determined by the DHS to pose a high level of security risk are required to prepare and submit Security Vulnerability Assessments and Site Security Plans, and comply with other regulatory requirements involving inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. While the DHS has determined that Bluewater will not be a covered facility at this time, it has not issued a determination for Pine Prairie; however, we do not anticipate compliance costs associated with the interim rule to have a material adverse affect on our business, financial position, or results of operations.

Pipeline Safety

As part of our natural gas storage operations, we own and operate pipeline header systems connecting our natural gas storage facilities to various interstate pipelines. As a result, our pipeline operations are subject to regulation by the

Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA). The NGPSA regulates safety requirements in the design, installation, testing, construction, operation and maintenance of gas pipeline facilities. The NGPSA has since been amended by the Pipeline Safety Act of 1992 (PSA), the Pipeline Safety Improvement Act of 2002

(PSIA), and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES). These amendments have imposed additional safety requirements on pipeline operators such as the development of a written qualification program for individuals performing covered tasks on pipeline facilities and the implementation of pipeline integrity management programs. These integrity management plans require more frequent inspections and other preventative measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. Accordingly, we will continue to focus on pipeline integrity management for any of the pipelines we currently own or acquire in the future, and significant additional expenses could be incurred if new or more stringent pipeline safety requirements are implemented. We believe that our operations are in substantial compliance with all existing federal, state, and local pipeline safety laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations.

Occupational Safety and Health

Our operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (OSHA) and comparable state statutes designed to protect the health and safety of workers. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act, and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local governmental authorities, and the public. Our operations are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process that involves a chemical at or above specified thresholds or any process that involves 10,000 pounds or more of a flammable liquid or gas in one location. We believe that our operations are in substantial compliance with all existing federal, state, and local occupations health and safety laws and regulations and that such laws and regulations will not have a material adverse effect on our business, financial position, or results of operations.

Seasonality

Because a high percentage of our baseline cash flow is derived from fixed-capacity reservation fees under multi-year contracts, our revenues are not generally seasonal in nature, nor are they typically affected by weather and price volatility. Weather impacts natural gas demand for power generation and heating purposes, which in turn influences the value of storage across our systems. Peak demand for natural gas typically occurs during the winter months, caused by the heating load, although certain markets such as the Florida market peak in the summer months due to cooling demands.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we (or entities in which we own an interest) 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 facilities are located are owned by us (or entities in which we own an interest) in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our major facilities are located are held by us (or entities in which we own an interest) pursuant to leases between us (or entities in which we own an interest), as lessee, and the fee owner of the lands, as lessors. We believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any material 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 license, and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses.

In May 2006, in order to receive a substantial tax exemption with respect to a portion of the Pine Prairie facility located in Evangeline Parish, Louisiana, we sold a portion of the facility located in the parish to the Industrial Development Board No. 1 of the Parish of Evangeline State of Louisiana, Inc. and entered into a

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15 year agreement to lease back such leased portion of the facility. Simultaneously with the execution of the lease, the Industrial Development Board issued and sold $50 million in bonds to us. Our rental obligations under the lease consist of an amount equal to the annual interest payment due from the Industrial Development Board on the bonds and the amount (if any) required for repayment in full of the outstanding indebtedness with respect to the bonds at the end of the lease term. Additionally, we are required to pay an annual $15,000 administrative fee to the Industrial Development Board, as well as reasonable fees, expenses and charges of the trustee in connection with the bonds.

The lease has a 15-year term, which commenced in January 2008, and is terminable by us upon payment to the Industrial Development Board of the amount required for repayment in full of its outstanding indebtedness under the bonds. We also have an option to purchase the leased properties at any time during the lease term for the sum of $5,000 plus the amount required for the repayment in full of any outstanding indebtedness under the bonds.

We are not subject to ad valorem property tax in the Parish of Evangeline for the property included in this arrangement during the term of the lease except for ad valorem tax on inventory. We are required to make certain annual payments in lieu of ad valorem property taxes, including (i) a fee not to exceed $45,000 per annum with respect to a portion of our header system known as the Chalk Line and (ii) beginning in 2010, an amount calculated as the difference between $500,000 and a three year average of ad valorem inventory tax revenues applicable to natural gas stored in the facility for the prior three consecutive calendar years.

The passive ownership of the facilities by the Industrial Development Board will not result in any impact to the operation of the Pine Prairie facility. In addition, the tax exemption enables Pine Prairie to offer more competitively priced storage services to respond to market forces.

Insurance

We share insurance coverage with PAA, for which we reimburse PAA s general partner pursuant to the terms of the omnibus agreement. To the extent PAA experiences covered losses under the insurance policies, the limit of our coverage for potential losses may be decreased. Our insurance program includes general liability insurance, auto liability insurance, worker s compensation insurance, and property insurance in amounts which management believes are reasonable and appropriate.

Employees

Plains All American GP LLC employs all of our personnel. We are managed and operated by the directors and officers of our general partner. We rely on an omnibus agreement with Plains All American GP LLC to provide us with employees needed to carry out our operations.

Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. We are also a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. Please read Regulation Natural Gas Storage Regulation.

MANAGEMENT

Partnership Management and Governance

Our general partner will manage our operations and activities. The directors of our general partner will oversee our operations. Unitholders will not be entitled to elect our general partner or the directors of our general partner and will not participate in the management of our operations. As a general partner, our general partner is liable for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. Our general partner has the discretion to incur indebtedness or other obligations on our behalf on a non-recourse basis to the general partner and we expect that it will do so.

The officers of our general partner will be employed by PAA s general partner and will manage the day-to-day affairs of our business. Certain of our officers will devote a substantial portion of their time to managing our business, while other officers will have responsibilities for both us and PAA. We will also utilize a significant number of employees of PAA s general partner to operate our business and provide us with general and administrative services.

We will enter into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we will agree upon certain aspects of our relationship with them, including the provision by PAA s general partner to us of certain general and administrative services and employees, our agreement to reimburse PAA s general partner for the cost of such services and employees, certain indemnification obligations, the use by us of the name PAA and related marks, and other matters. Please read Certain Relationships and Related Transactions Agreements Governing the Transactions Omnibus Agreement. Additionally, the omnibus agreement will not increase or decrease our general partner s fiduciary duties to us under our partnership agreement. For more information on the fiduciary duties of our general partner, please read Conflicts of Interest and Fiduciary Duties Duties of Our General Partner.

Directors of our General Partner

PAA is the sole member of our general partner and will have the right to elect all seven members to the board of directors of our general partner. Subject to the transition described under Our Board Committees Audit Committee below, at least three of the members of our general partner s board of directors must be independent (as defined in applicable NYSE and SEC rules) and eligible to serve on the audit committee. At least two of such directors must also meet the criteria for service on a conflicts committee in accordance with our partnership agreement. Mr. Victor Burk joined the board of our general partner prior to the effectiveness of our registration statement, and Mr. Bobby S. Shackouls is expected to join the board of our general partner immediately after the time our common units become listed for trading on the NYSE (the listing date). Our general partner s board of directors has determined that Messrs. Burk and Shackouls satisfy the NYSE and SEC requirements for independence. The board has also determined that Mr. Burk is an audit committee financial expert, as defined by the SEC.

In evaluating director candidates, PAA will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board s ability to manage and direct the affairs and business of the partnership, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Our Board Committees

Because we are a limited partnership, the listing standards of the NYSE do not require that we or our general partner have a majority of independent directors or a nominating or compensation committee of the board of directors. We are, however, required to have an audit committee of at least three members, and all of its members are required to be independent as defined by the NYSE.

Audit Committee. We have one director, Mr. Victor Burk, who satisfies the applicable NYSE and SEC requirements for independence and eligibility to serve on the audit committee. Within 90 days of the listing

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date, we will have a total of two independent directors who meet the requirements for audit committee service. Within one year of the listing date, we will have a total of three independent directors who meet the requirements for audit committee service.

Pursuant to the NYSE listing standards, a director will be considered independent if the board determines that he or she does not have a material relationship with our general partner or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with our general partner or us) and otherwise meets the board s stated criteria for independence. These three board members will serve as the members of the audit committee.

In addition to these general independence requirements, as required by the Sarbanes-Oxley Act of 2002, the SEC has adopted rules that direct national securities exchanges and associations to prohibit the listing of securities of a public company if members of its audit committee do not satisfy additional independence requirements. In order to meet this standard, a member of an audit committee may not receive any consulting fee, advisory fee or other compensation from the public company other than fees for service as a director or committee member, and may not be considered an affiliate of the public company. Subject to the transition period described above, the board of directors of our general partner expects that all members of its audit and conflicts committees will satisfy this heightened independence requirement.

Further, SEC rules require that a public company disclose whether or not its audit committee has an audit committee financial expert as a member. An audit committee financial expert is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. The board of directors of our general partner anticipates that at least one of its independent directors will satisfy the definition of audit committee financial expert.

Compensation Committee. Our general partner s board of directors intends to establish a compensation committee. The compensation committee will administer our Long Term Incentive Plan and other equity and executive compensation plans.

Conflicts Committee. Our partnership agreement provides for the establishment or activation of a conflicts committee, as circumstances warrant, to review conflicts of interest between us and our general partner or between us and PAA or its affiliates. Such a committee would consist of a minimum of two members, none of whom can be (i) an officer or employee of our general partner, (ii) a holder of any ownership interest in us, our subsidiaries, our general partner or its affiliates (other than (a) our common units or (b) other awards granted to such director under our LTIP) or (iii) an officer, director or employee of any affiliate of our general partner or any associate of such affiliate, and each of whom must meet the independence standards for service on an audit committee established by the NYSE and the SEC. A director will not be precluded from serving on such committee due to the ownership of common units of PAA or other indirect interests of our general partner unless the board of directors of our general partner determines, after taking into account the totality of the specific circumstances involving such director, that such ownership will likely have an adverse impact on the ability of such director to act in an independent manner with respect to the matter submitted to the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties owed to us or our unitholders.

Board Leadership Structure and Role in Risk Oversight

Our CEO also serves as Chairman of the Board. The board has no policy with respect to the separation of the offices of chairman and CEO; rather, that relationship is currently defined and governed by the limited liability company agreement of our general partner, which requires coincidence of the offices. We do not have a lead independent director. The chairmanship of non-management executive sessions of the board rotates among the non-management directors, sequenced alphabetically by last name. Directors of our general partner are designated or elected by its sole member, PAA. Accordingly, unlike holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

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The management of enterprise-level risk may be defined as the process of identification, management and monitoring of events that present opportunities and risks with respect to creation of value for our unitholders. The board has delegated to management the primary responsibility for enterprise-level risk management, while the board has retained responsibility for oversight of management in that regard. Management will offer an enterprise-level risk assessment to the Board at least once every year.

Directors and Executive Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers, directors, the director nominee and certain other officers and key employees of our general partner. Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board. There are no family relationships among any of our directors or executive officers. Some of our directors and executive officers also serve as directors or executive officers of PAA.

Name	Age (as of 12/31/2009)	Position with Our General Partner
Greg L. Armstrong*	51	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	52	Vice Chairman and Director
Dean Liollio*	51	President and Director
Al Swanson*	45	Senior Vice President, Chief Financial Officer and Director
Richard McGee*	48	Vice President Legal and Business Development and Secretary
Dan Noack	39	Vice President Operations
Richard Tomaski	38	Vice President Marketing
Tina L. Summers*	40	Vice President Accounting and Chief Accounting Officer
Donald C. O Shea	39	Controller
Victor Burk	60	Director
Bobby S. Shackouls	59	Director Nominee

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

Greg L. Armstrong has served as Chairman of the Board, Chief Executive Officer and Director of our general partner since January 2010 and as Chairman of the Board, Chief Executive Officer and Director of PAA s general partner since PAA s formation in 1998. In addition, he was President, Chief Executive Officer and director of Plains Resources Inc. from 1992 to May 2001. He previously served Plains Resources as President and Chief Operating Officer from October to December 1992; Executive Vice President and Chief Financial Officer from June to October 1992; Senior Vice President and Chief Financial Officer from 1991 to 1992; Vice President and Chief Financial Officer from 1984 to 1991; Corporate Secretary from 1981 to 1988; and Treasurer from 1984 to 1987. Mr. Armstrong is also a director of National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. Our general partner s limited liability company agreement specifies that Mr. Armstrong, as the Chief Executive Officer of the general partner, be a member of the board of directors. In addition, we believe that Mr. Armstrong s experience as chairman of the board and chief executive officer of PAA and his extensive knowledge of the energy industry will bring substantial experience and leadership skills to the board.

Harry N. Pefanis has served as Vice Chairman and Director of our general partner since January 2010 and as President and Chief Operating Officer of PAA s general partner since PAA s formation in 1998. In addition, he was

Executive Vice President Midstream of Plains Resources from May 1998 to May 2001. He previously served Plains Resources as Senior Vice President from February 1996 until May 1998; Vice President Products Marketing from 1988 to February 1996; Manager of Products Marketing from 1987 to

1988; and Special Assistant for Corporate Planning from 1983 to 1987. Mr. Pefanis was also President of several former midstream subsidiaries of Plains Resources until PAA s formation. Mr. Pefanis is also a director of Settoon Towing. We believe that Mr. Pefanis extensive energy industry background, particularly the five years he has spent serving as part of the management team of PAA s natural gas storage business, brings important experience and skill to the board.

Dean Liollio has served as President and Director of our general partner since January 2010. He has served as President of PAA s natural gas storage business since November 2008. Prior to joining PAA s natural gas storage business, Mr. Liollio served as President, Chief Executive Officer and Director of Energy South, Inc. from August 2006 until its acquisition by Sempra in October 2008. He previously spent 23 years at Centerpoint Energy, most recently serving as Division President and COO of Southern Gas Operations. We believe that Mr. Liollio s more than 25 years of experience in the energy industry, most notably his experience managing natural gas storage operations, including as a director and chief executive officer of a public natural gas storage company, will provide a critical resource and skill set to the board.

Al Swanson has served as Senior Vice President, Chief Financial Officer and Director of our general partner since January 2010 and as Senior Vice President and Chief Financial Officer of PAA s general partner since November 2008. He previously served as Senior Vice President Finance of PAA s general partner from August 2008 until November 2008 and as Senior Vice President Finance and Treasurer from August 2007 until August 2008. He served as Vice President Finance and Treasurer of PAA s general partner from August 2005 to August 2007, as Vice President and Treasurer from February 2004 to August 2005 and as Treasurer from May 2001 to February 2004. In addition, he held finance related positions at Plains Resources including Treasurer from February 2001 to May 2001 and Director of Treasury from November 2000 to February 2001. Prior to joining Plains Resources, he served as Treasurer of Santa Fe Snyder Corporation from 1999 to October 2000 and in various capacities at Snyder Oil Corporation including Director of Corporate Finance from 1998, Controller SOCO Offshore, Inc. from 1997, and Accounting Manager from 1992. Mr. Swanson began his career with Apache Corporation in 1986 serving in internal audit and accounting. Mr. Swanson has nearly 25 years of experience in the energy industry, serving a number of public companies in the areas of finance, treasury, accounting and internal audit. We believe that this extensive background, coupled with his expertise as chief financial officer of PAA, will lend significant financial and accounting experience and skill to the board.

Richard McGee has served as Vice President Legal and Business Development and Secretary of our general partner since January 2010. He has served as Vice President of PAA s natural gas storage business since September 2009. From January 1999 to July 2009, he was employed by Duke Energy, serving as President of Duke Energy International from October 2001 through July 2009 and serving as general counsel of Duke Energy Services from January 1999 through September 2001. He previously spent 12 years at Vinson & Elkins L.L.P., where he was a partner with a focus on acquisitions, divestitures and development work for various clients in the energy industry.

Dan Noack has served as Vice President Operations of our general partner since January 2010. He has served as Vice President of Operations of PAA s natural gas storage business since July 2008. Most recently, from January 2005 until June 2008, he served as storage manager for Energy Transfer Partners responsible for their three storage assets and 76 Bcf of working gas capacity, and from January 2002 until December 2004, he served as a storage consultant for El Paso Field Services (GulfTerra) responsible for their eight storage assets, 26 cavern wells, 23 Bcf of working gas capacity and 40 MMbbls of liquid storage capacity.

Richard Tomaski has served as Vice President Marketing of our general partner since January 2010. He has served as Vice President of PAA s natural gas storage business since September 2005. From April 2002 until September 2005, he served as Vice President of Sempra Energy Trading, where he had responsibility for natural gas trading and gas storage marketing at Bluewater and Pine Prairie. From August 1996 until April 2002, he served in several capacities with Enron Corp. and Enron North America.

Tina L. Summers has served as Vice President Accounting and Chief Accounting Officer of our general partner since January 2010 and as Vice President Accounting and Chief Accounting Officer of PAA s general partner since June 2003. She served as Controller from April 2000 until she was elected to her current

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position. From January 1998 to January 2000, Ms. Summers served as a consultant to Conoco de Venezuela S.A. She previously served as Senior Financial Analyst for Plains Resources from October 1994 to July 1997.

Donald C. O Shea has served as Controller of our general partner since February 2010. Previously he served as Director, Special Projects of PAA s general partner from November 2009 to January 2010. Prior to joining us, Mr. O Shea spent 15 years working for the accounting firm PricewaterhouseCoopers LLP.

Victor Burk has served as Director of our general partner since April 2010 and has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm since April 2009. From 2005 to 2009, Mr. Burk was the global energy practice leader for Spencer Stuart, a privately owned executive recruiting firm. Prior to joining Spencer Stuart, Mr. Burk served as managing partner of Deloitte & Touche s global oil and natural gas group from 2002 to 2005. He began his professional career in 1972 with Arthur Andersen and served as managing partner of Arthur Andersen s global oil and natural gas group from 1989 until 2002. Mr. Burk is on the Board of Directors of EV Energy Partners, a publicly traded limited partnership engaged in the acquisition, development and production of oil and natural gas. Mr. Burk also serves as a board member of the Houston Producers Forum, the Independent Petroleum Association of America (Southeast Texas Region) and the Sam Houston Area Council of the Boy Scouts of America. He received a BBA in Accounting from Stephen F. Austin University, graduating with highest honors. We believe that Mr. Burk s background, spanning over 30 years of extensive public accounting and consulting in the energy industry, coupled with his demonstrated leadership abilities, will bring valuable expertise and insight to the board.

Bobby S. Shackouls has agreed to serve as a Director of our general partner immediately after the listing date. Mr. Shackouls served as Chairman of Burlington Resources Inc. from 1997 until its acquisition by ConocoPhillips in 2006. He also served as President and Chief Executive Officer of Burlington Resources from 1995 until 2006. Mr. Shackouls currently serves as a director of ConocoPhillips and The Kroger Co. We believe that Mr. Shackouls extensive experience within the energy industry offers valuable perspective and, in tandem with his long history of leadership as the CEO of a public company make him highly qualified to serve as a member of the board.

Compensation of Our Officers

We and our general partner were formed in January 2010. Accordingly, our general partner has not accrued any obligations with respect to management incentive or retirement benefits for our directors and officers for the fiscal year ended December 31, 2009 or for any prior periods.

The officers of our general partner will be employed by PAA s general partner and will manage the day-to-day affairs of our business. Certain of our officers are dedicated to managing our business and will devote the substantial majority of their time to our business, while other officers will have responsibilities for both us and PAA and will devote less than a majority of their time to our business. Because the executive officers of our general partner are employees of PAA s general partner, compensation will be paid by PAA s general partner and reimbursed by us. The officers of our general partner, as well as the employees of PAA s general partner who provide services to us, may participate in employee benefit plans and arrangements sponsored by PAA, including plans that may be established in the future. Our general partner has not entered into any employment agreements with any of our officers. We anticipate that, in connection with the closing of this offering, the board of directors of our general partner will grant awards to our key employees and our outside directors pursuant to the Long Term Incentive Plan described below; however, the board has not yet made any determination as to the number of awards, the type of awards or when the awards would be granted. Certain of our key employees hold grants under PAA s Long Term Incentive Plan. It is our intent to replace such grants with grants of equivalent value under our Long Term Incentive Plan following the closing of this offering. We anticipate that the vesting of our equity awards to the officers of our general partner will be tied to time and performance thresholds. We expect that annual bonuses will be determined based on financial performance as measured across the storage season (as opposed to the calendar year), which begins on April 1 of any given year and ends on March 31 of the following year.

Because our general partner was recently formed and has not accrued any compensation obligations, we generally are not presenting historical compensation information. We have, however, included below certain

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compensation information for Messrs. Liollio and McGee, who we anticipate will dedicate the majority of their time to the management and operation of our business and will be designated as named executive officers for purposes of future compensation disclosures. Messrs. Liollio and McGee each entered into a letter agreement with PAA s general partner outlining the basic terms of their employment. These letter agreements have been filed as exhibits to the registration statement of which this prospectus forms a part. Mr. Liollio s employment commenced on November 1, 2008. Pursuant to Mr. Liollio s letter agreement, he is entitled to receive annual salary of $250,000 and a minimum quarterly bonus of $85,000 pursuant to a quarterly bonus program. In addition, Mr. Liollio s annual target bonus is 225% of his base salary. During 2009, Mr. Liollio was paid $250,000 in the form of salary and approximately $323,000 in the form of quarterly bonuses. During the second quarter of 2009, Mr. Liollio earned an annual bonus of $250,000 that included a pro rated amount for his 2008 storage season service (from commencement of his employment in November 2008 through March 31, 2009). Mr. Liollio will receive an annual bonus in the second quarter of 2010 for his 2009 storage season service. As a result of his extraordinary efforts in connection with our preparation to become a publicly traded partnership, Mr. Liollio received a special bonus of $800,000 in January 2010. In connection with his initial employment, Mr. Liollio received a grant of 60,000 phantom units under PAA s long term incentive plan, which are subject to time and performance vesting conditions.

Mr. McGee s employment commenced on September 15, 2009. Pursuant to Mr. McGee s letter agreement, he is entitled to receive annual salary of $200,000 and a minimum annual bonus of $300,000. Mr. McGee s target bonus is 150% of his base salary. During 2009, Mr. McGee was paid approximately $59,000 in the form of pro-rated salary and will receive an annual bonus in the second quarter of 2010 that will include a pro rated amount for his 2009 storage season service (from commencement of his employment in September 2009 through March 31, 2010). In connection with his initial employment, Mr. McGee received a grant of 36,000 phantom units under PAA s long term incentive plan, which are subject to time and performance vesting conditions. It is our intent to replace the equity grants previously received by Messrs. Liollio and McGee with grants of equivalent or greater value under our Long Term Incentive Plan. Because Messrs. Liollio and McGee were not named executive officers of PAA during 2009, their compensation is neither presented nor discussed in PAA s annual report on Form 10-K.

Messrs. Armstrong, Pefanis and Swanson and Ms. Summers are executive officers of the general partner of PAA as described above and, other than for Ms. Summers, information relating to their compensation is set forth in PAA s annual report on Form 10-K.

Our Long-Term Incentive Plan

Our general partner and PAA as our limited partner have adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan for the employees, directors and consultants of our general partner and its affiliates, including PAA, who perform services for us. To date, no awards have been made under the Long Term Incentive Plan. The description of the Long Term Incentive Plan set forth below is a summary of the material features of the Long Term Incentive Plan. This summary, however, does not purport to be a complete description of all the provisions of the Long Term Incentive Plan. This summary is qualified in its entirety by reference to the Long Term Incentive Plan, a copy of which has been filed as an exhibit to this registration statement.

The Long Term Incentive Plan consists of restricted units, phantom units, unit options, unit appreciation rights, unit awards and deferred common units. The Long Term Incentive Plan limits the number of common units that may be delivered pursuant to awards under the plan to 3,000,000 units. Units forfeited or withheld to satisfy tax withholding obligations will again become available for delivery pursuant to other awards. In addition, if an award is forfeited, canceled or otherwise terminates, expires or is settled without the delivery of units, the units subject to such award will again be available for new awards under the Long Term Incentive Plan. Common units to be delivered pursuant to awards under the Long Term Incentive Plan may be newly issued common units, common units acquired by us in the open market, common units acquired by us from any other person, or any combination of the foregoing. If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase.

Administration. The Long Term Incentive Plan will be administered by the board of directors and compensation committee of our general partner. The board of directors of our general partner may terminate or amend the Long Term Incentive Plan at any time with respect to any units for which a grant has not yet been made. Our board of directors also has the right to alter or amend the Long Term Incentive Plan or any part of the Long Term Incentive Plan from time to time, including increasing the number of units that may be granted, subject to unitholder approval as may be required by the exchange upon which the common units are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The Long Term Incentive Plan will expire upon its termination by the board of directors or, if earlier, when no units remain available under the Long Term Incentive Plan for awards. Upon termination of the Long Term Incentive Plan, awards then outstanding will continue pursuant to the terms of their grants.

Restricted Units. A restricted unit is a common unit that vests over a period of time and that during such time is subject to forfeiture. In the future, the plan administrator may determine to make grants of restricted units under the Long Term Incentive Plan to employees, directors and consultants, containing such terms as the plan administrator determines. The plan administrator will determine the period over which restricted units will vest. The plan administrator, in its discretion, may base its determination upon the achievement of specified financial objectives or other events. In addition, the restricted units may vest upon a change in control, as defined in the relevant grant letter. Distributions made on restricted units may be subjected to vesting provisions. If a grantee s employment, consulting arrangement or membership on the board of directors terminates for any reason, the grantee s restricted units will be automatically forfeited unless, and to the extent, the plan administrator or the terms of the award agreement provide otherwise.

Phantom Units. A phantom unit entitles the grantee to receive a common unit upon the vesting of the phantom unit or, in the discretion of the plan administrator, cash equivalent to the value of a common unit. In the future, the plan administrator may determine to make grants of phantom units under the Long Term Incentive Plan to employees, consultants and directors containing such terms as the plan administrator determines. The plan administrator will determine the period over which phantom units granted to employees, consultants and members of our board will vest. The plan administrator, in its discretion, may base its determination upon the achievement of specified financial objectives or other events. In addition, the phantom units may vest upon a change in control, as defined in the relevant grant letter. If a grantee s employment, consulting arrangement or membership on the board of directors terminates for any reason, the grantee s phantom units will be automatically forfeited unless, and to the extent, the plan administrator or the terms of the award agreement provide otherwise.

The plan administrator, in its discretion, may grant distribution equivalent rights, which we refer to as DERs, with respect to a phantom unit. DERs entitle the grantee to receive a cash payment equal to the cash distributions made on a common unit during the period the phantom unit is outstanding. The plan administrator will establish whether the DERs are paid currently, when the tandem phantom unit vests or on some other basis.

We intend the grant of restricted units and issuance of any common units upon vesting of the phantom units under the Long Term Incentive Plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

Unit Options and Unit Appreciation Rights. The Long Term Incentive Plan also permits the grant of options covering common units and unit appreciation rights. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units as determined by the plan administrator. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the plan administrator may determine that are consistent with the plan; however, a unit option or unit appreciation right must have an exercise price greater than or equal to the fair market value of a common unit on the date of grant.

In general, unit options and unit appreciation right will become exercisable over a period determined by the plan administrator. The plan administrator may, in its discretion, provide that unit options and unit appreciation rights will become exercisable upon a change in control, as defined in the relevant grant letter. If a grantee s employment, consulting arrangement or membership on the board of directors terminates for any reason, the grantee s unvested unit options and unit appreciation rights will be automatically forfeited unless, and to the extent, the award agreement or plan administrator provides otherwise. The plan administrator will determine the method or methods that may be used to pay the exercise price of unit options. The availability of unit options and unit appreciation rights is intended to furnish additional compensation to participants and to align their interests with those of our unit holders.

Unit Awards. The Long Term Incentive Plan permits the grant of common units that are not subject to vesting restrictions. Unit awards may be in lieu of or in addition to other compensation payable to an eligible individual. The availability of unit awards is intended to furnish additional compensation to plan participants and to align their economic interests with those of common unit holders.

Deferred Awards. Awards granted under the Long Term Incentive Plan may be deferred to the extent permitted by the plan administrator in its discretion. The plan administrator may, for example, determine to make grants of deferred common units, which would vest immediately upon issuance and be delivered to the holder upon termination or retirement from our general partner or upon some later date that is selected by the participant or the plan administrator in accordance with Section 409A of the Internal Revenue Code. Deferred common units would typically receive all cash or other distributions paid by us on account of our common units.

U.S. Federal Income Tax Consequences of Awards Under the Long Term Incentive Plan. Generally, when restricted units, phantom units, deferred common units, unit options or unit appreciation rights are granted, there are no income tax consequences for the participant or us. Upon the payment to the participant of common units and/or cash in respect of the award of phantom units or deferred common units or the release of restrictions on restricted units, including any distributions that have been made thereon, the participant recognizes compensation equal to the fair market value of the cash and/or units as of the date of delivery or release. A participant generally recognizes compensation income with respect to unit options and unit appreciation rights at the time the award is exercised in an amount equal to the excess of the fair market value of a unit on the date of exercise over the exercise price of the award, multiplied by the number of units subject to the award. Unit awards that are not subject to vesting restrictions or deferral typically represent taxable income on the date of grant. Unless other arrangements are made, the plan administrator is authorized to withhold from any payment due under any award or from any compensation or other amount owing to a participant, an amount (in cash, units, units that would otherwise be issued pursuant to the award, or other property) of any applicable taxes payable with respect to the grant of an award, its settlement, its exercise or the lapse of restrictions applicable to an award or in connection with any payment relating to an award or the transfer of an award and to take such other actions as may be necessary to satisfy the withholding obligations with respect to an award.

Class B Units of Our General Partner

We expect our general partner to authorize the issuance to members of our management team Class B units, each representing a profits interest in our general partner. The Class B units will be limited to proportionate participation in cash distributions paid by our general partner above specified quarterly distribution levels.

The cost of the obligations represented by the Class B units will be borne solely by our general partner. We will not be obligated to reimburse our general partner for such costs and any distributions made on such Class B units will not reduce the amount of cash available for distribution to our unitholders. Under generally accepted accounting principles, however, the Class B units represent an equity compensation plan for our benefit. Accordingly, once the likelihood of achievement of a performance threshold is considered probable, we will record an expense related to the fair market value of the associated interest at the date of grant, proportionate to the relevant service period incurred through such date. Any balance will be amortized over the remaining service period through the achievement of such performance threshold. An offsetting entry will be recorded to partners capital to reflect a capital contribution from our general partner equal to the amount recorded as expense in our financial statements.

Terms of each grant will vary, but are expected to include performance benchmarks that encourage and reward the growth of our partnership through acquisitions and other terms that encourage retention.

Compensation of Our Directors

The officers or employees of our general partner or of PAA s general partner who also serve as directors of our general partner will not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not officers or employees of our general partner or of PAA s general partner will receive compensation as set by our general partner s board of directors upon recommendation from our general partner s compensation committee. In addition, non-employee directors will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees.

Each director will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Compensation Committee Interlocks and Insider Participation

Our general partner s board of directors intends to establish a compensation committee, but has yet to do so.

Compensation Discussion and Analysis

All of our executive officers and other personnel necessary for our business to function will be employed and compensated by PAA s general partner, subject to reimbursement by us. We and our general partner were formed in January 2010, therefore, we incurred no cost or liability with respect to compensation of our executive officers, nor has our general partner accrued any liabilities for management incentive or retirement benefits for our executive officers for the fiscal year ended December 31, 2009 or for any prior periods.

Responsibility and authority for compensation-related decisions for executive officers dedicated to our business will reside with the compensation committee of our general partner. Responsibility and authority for compensation-related decisions for executive officers with responsibilities to both us and PAA will reside with the compensation committee of PAA s general partner. Our officers will manage our business as part of the service provided by PAA under the omnibus agreement, and the compensation for all of our executive officers will be indirectly paid by us through reimbursements to PAA. Our general partner s compensation committee will also be responsible for the future administration of our LTIP and for compensation of our general partner s non-employee directors.

We expect that the future compensation of our executive and non-executive officers will be structured in a manner similar to that of PAA and, accordingly, will include a significant component of incentive compensation based on our performance. PAA employs a compensation philosophy that emphasizes pay-for-performance (primarily the ability to increase sustainable quarterly distributions to unitholders), both on an individual and entity level, and places the majority of each officer s compensation at risk. PAA believes its pay-for-performance approach aligns the interests of its executive officers with that of its unitholders, and at the same time enables PAA to maintain a lower level of base overhead in the event its operating and financial performance fails to meet expectations. PAA designs its executive compensation to attract and retain individuals with the background and skills necessary to successfully execute its business model in a demanding environment, to motivate those individuals to reach near-term and long-term goals in a way that aligns their interest with that of its unitholders, and to reward success in reaching such goals. PAA uses three primary elements of compensation to fulfill that design salary, cash bonus and long-term equity incentive awards.

Cash bonuses and equity incentives (as opposed to salary) represent the performance driven elements. They are also flexible in application and can be tailored to meet PAA s objectives. The determination of specific individuals cash bonuses reflects their relative contribution to achieving or exceeding annual goals, and the determination of specific individuals long-term incentive awards is based on their expected contribution in respect of longer term performance objectives. PAA does not maintain a defined benefit or pension plan for its executive officers, because it believes such plans primarily reward longevity rather than performance. PAA provides a basic benefits package generally to all employees, which includes a 401(k) plan and health, disability and life insurance. Employees provided to us under the omnibus agreement will enjoy the same basic benefits. In instances considered necessary for the execution of their job responsibilities, PAA also reimburses certain of its executive officers and other employees for club dues and similar expenses.

Relation of Compensation Policies and Practices to Risk Management

We anticipate that our compensation policies and practices will reflect the same philosophy and approach as PAA s. Accordingly, such policies and practices will be designed to provide rewards for short-term and long-term performance, both on an individual basis and at the entity level. In general, optimal financial and operational performance, particularly in a competitive business, requires some degree of risk-taking. Accordingly, the use of compensation as an incentive for performance can foster the potential for management and others to take unnecessary or excessive risks to reach performance thresholds which qualify them for additional compensation. For us, such risks would primarily attach to the commercial marketing activities that we intend to develop, as well as to the execution of capital expansion projects and acquisitions and the realization of associated returns.

From a risk management perspective, our policy will be to conduct our commercial activities within pre-defined risk parameters that are closely monitored and are structured in a manner intended to control and minimize the potential for unwarranted risk-taking. See Management s Discussion and Analysis Future Trends and Outlook Commercial Management Activities. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

We expect our compensation arrangements to contain a number of design elements that serve to minimize the incentive for taking unwarranted risk to achieve short-term, unsustainable results. Those elements include delaying the rewards and subjecting such rewards to forfeiture for terminations related to violations of our risk management policies and practices or of our code of conduct. See Compensation Discussion and Analysis.

In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth the beneficial ownership of our units that, upon the consummation of this offering and the related transactions and assuming that underwriters do not exercise their option to purchase up to 1,758,000 additional common units, will be owned by:

each person or group of persons known by us to be a beneficial owner of 5% or more of the then outstanding units;

each member of and nominee to the board of directors of our general partner;

each executive officer of our general partner; and

all directors, the director nominee and executive officers of our general partner as a group.

Name and Address of Beneficial Owner	Common Units to be Beneficially Owned	Percentage of Common Units to be Beneficially Owned	Series A Subordinated Units to be Beneficially Owned	Percentage of Series A Subordinated Units to be Beneficially Owned	Series B Subordinated Units to be Beneficially Owned	Percentage of Series B Subordinated Units to be Beneficially Owned	Percentage of Total Common and Subordinated Units to be Beneficially Owned
Plains All American Pipeline, L.P.[(1)]	19,864,529	62.9%	13,934,351	100%	11,500,000	100%	79.4%
Greg L. Armstrong	100,000	*					*
Harry N. Pefanis	65,000	*					*
Dean Liollio	26,700	*					*
Al Swanson	37,500	*					*
Richard McGee	20,000	*					*
Tina L. Summers							
Victor Burk	1,000	*					*
Bobby S. Shackouls							
All directors, the director nominee and executive officers of our general partner as a group (8 persons)	250,200	*					*

* Less than 1%

(1) The address for Plains All American Pipeline, L.P. is 333 Clay Street, Suite 1600, Houston, Texas 77002.

The following table sets forth, as of April 21, 2010, the number of common units of Plains All American Pipeline, L.P. owned by beneficial owners of 5% or more of PAA s units, each of the executive officers, directors, and the director nominee of our general partner and all directors, the director nominee and executive officers of our general partner as a group. As of April 21, 2010, there were 136,135,988 common units of Plains All American Pipeline issued and outstanding.

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Name and Address of Beneficial Owner	PAA Common Units Owned Directly or Indirectly[(1)]	Percentage of PAA Common Units Beneficially Owned
Paul G. Allen[(2)]	16,293,379[(2)]	12.0%[(3)]
Vulcan Energy Corporation[(4)]	12,390,120	9.1%
Richard Kayne/Kayne Anderson Capital Advisors, L.P.[(5)]	7,281,859[(5)]	5.3%
Greg L. Armstrong	467,490	*
Harry N. Pefanis	301,118	*
Dean Liollio	10,000	*
Al Swanson	32,803	*
Richard McGee		
Tina L. Summers	29,043	*
Victor Burk	500	*
Bobby S. Shackouls	3,000	*
All directors, the director nominee and executive officers of our general partner as a group (8 persons)	843,954	*

* Less than 1%

(1) Includes the following phantom units under PAA s Long-Term Incentive Plans, which are expected to vest within 60 days after April 1, 2010; Mr. Armstrong, 120,000; Mr. Pefanis, 80,000; Mr. Swanson, 17,000; Ms. Summers, 13,500; and all directors, the director nominee and executive officers of our general partner as a group, 230,500.

(2) Mr. Allen owns approximately 80% of the outstanding shares of common stock of Vulcan Energy Corporation. Mr. Allen also controls Vulcan Capital Private Equity I LLC (Vulcan I LLC), which is the record holder of 3,706,044 common units of PAA, and Vulcan Capital Private Equity II LLC (together with Vulcan I LLC, Vulcan LLC), which is the record holder of 197,215 common units of PAA. The address for Mr. Allen and Vulcan LLC is 505 Fifth Avenue S, Suite 900, Seattle, Washington 98104. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of PAA s partner interests held by Vulcan Energy Corporation or any of its affiliates.

(3) Giving effect to the indirect ownership by Vulcan Energy Corporation of a portion of PAA s general partner, Mr. Allen may be deemed to beneficially own approximately 12.7% of PAA s total equity. Mr. Allen disclaims any deemed beneficial ownership, beyond his pecuniary interest, in any of PAA s partner interests held by Vulcan Energy Corporation or any of its affiliates.

(4) The address for Vulcan Energy Corporation is c/o Plains All American GP LLC, 333 Clay Street, Suite 1600, Houston, Texas 77002.

(5) Richard A. Kayne is Chief Executive Officer and Director of Kayne Anderson Investment Management, Inc., which is the general partner of Kayne Anderson Capital Advisors, L.P. (KACALP). Various accounts (including KAFU Holdings, L.P., which owns a portion of PAA s general partner) under the management or control of KACALP own 7,016,623 common units of PAA. Mr. Kayne may be deemed to beneficially own such units. In

addition, Mr. Kayne directly owns or has sole voting and dispositive power over 265,236 common units of PAA. Mr. Kayne disclaims beneficial ownership of any of PAA s partner interests other than units held by him or interests attributable to him by virtue of his interests in the accounts that own PAA s partner interests. The address for Mr. Kayne and Kayne Anderson Investment Management, Inc. is 1800 Avenue of the Stars, 2nd Floor, Los Angeles, California 90067.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

After this offering, assuming that the underwriters do not exercise their option to purchase additional common units, PAA will own 19,864,529 common units, 13,934,351 Series A subordinated units and 11,500,000 Series B subordinated units, representing an aggregate 77.9% limited partner interest in us. In addition, PAA will own our general partner, which will own a 2.0% general partner interest in us and all of our incentive distribution rights.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and any liquidation of the partnership, assuming that the underwriters do not exercise their option to purchase additional common units. These distributions and payments were determined by and among affiliated entities.

Formation stage	
The aggregate consideration received by PAA for the contribution of the assets and liabilities to us	19,864,529 common units; 13,934,351 Series A subordinated units; 11,500,000 Series B subordinated units; 2.0% general partner interest; and our incentive distribution rights.
Operational stage	
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98.0% to our unitholders pro rata, including PAA as the holder of common units and 13,934,351 Series A subordinated units, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% interest in us. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level, including the general partner s 2% general partner interest. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding common units and Series A subordinated units for four quarters, our general partner would receive an annual distribution of approximately $1.3 million on its general partner interest and PAA would receive an annual distribution of approximately $45.6 million on its common units and Series A subordinated units. If our general partner elects to reset the target distribution levels, it will be entitled to receive common units. The Series B subordinated units are not entitled to cash distributions unless and until they convert to Series A subordinated units or common units.

Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for the management of our partnership. Our general partner and its affiliates are reimbursed, however, for all direct and indirect expenses incurred on our behalf. Our general partner determines the amount of these expenses. In addition, we will reimburse

	PAA for the provision of various general and administrative services for our benefit pursuant to the omnibus agreement and the costs and expenses of employees provided to us. Please read Agreements Governing the Transaction Omnibus Agreement below.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests. Please read The Partnership Agreement Withdrawal or Removal of Our General Partner.
Liquidation stage	
Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements Governing the Transactions

We and other parties have or will enter into the various documents and agreements that will affect the offering transactions, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries, and the application of the proceeds of this offering. These agreements have been negotiated among affiliated parties. All of the transaction expenses incurred in connection with these transactions, including the expenses associated with transferring assets into our subsidiaries, will be paid from the proceeds of this offering.

Omnibus Agreement

Concurrently with the closing of our initial public offering, we will enter into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we will agree upon certain aspects of our relationship with them, including, among other things:

- the provision by PAA s general partner to us of certain general and administrative services and our agreement to reimburse PAA s general partner for such services;

- the provision by PAA s general partner of such employees as may be necessary to operate and manage our business, and our agreement to reimburse PAA s general partner for the expenses associated with such employees;

- certain indemnification obligations; and

- our use of the name PAA and related marks.

PAA s indemnification obligations will include certain liabilities relating to:

- for a period of three years after the closing of this offering, environmental liabilities, including (i) any violation or correction of violation of environmental laws associated with our assets, where a correction of violation would include assessment, investigation, monitoring, remediation, or other similar action and (ii) any event, omission or condition associated with the ownership of our assets (including presence of hazardous materials), including (A) the cost and expense of any assessment, investigation, monitoring, remediation or other similar action and (B) the cost and expense of any environmental or toxic tort litigation, provided that (i) the aggregate amount payable to us pursuant to this bullet point does not exceed $15 million and (ii) amounts are only payable to us pursuant to this bullet point after liabilities relating to this bullet point have exceeded $250,000;

until 60 days after the applicable statute of limitations, any of our federal, state and local income tax liabilities attributable to the ownership and operation of our assets and the assets of our subsidiaries prior to the closing of this offering or our formation transactions;

for a period of three years after the closing of this offering, the failure to have all necessary consents and governmental permits where such failure renders us unable to use and operate our assets in substantially the same manner in which they were used and operated immediately prior to the closing of this offering; and

for a period of three years after the closing of this offering, our failure to have (i) valid and indefeasible easement rights, rights-of-way, leasehold and/or fee ownership interest in the lands where our assets are located or (ii) valid title to the equity interests of the entities owning our assets and such failure prevents us from using or operating our assets in substantially the same manner as operated immediately prior to the closing of this offering.

In no event will PAA be obligated to indemnify us for any claims, losses or expenses or income taxes referred to above to the extent either (i) reserved for in our financial statements as of December 31, 2010, or (ii) we recover any such amounts under available insurance coverage, from contractual rights or other recoveries against any third party.

In addition, we will also agree to indemnify PAA and its general partner from any losses, costs or damages incurred by PAA or its general partner that are attributable to the ownership and operation of our assets and the assets of our subsidiaries following the closing of this offering, subject to the same limitations on PAA s indemnity to us.

With respect to the provision by PAA s general partner of certain general and administrative services and such management and operating services as may be necessary to manage and operate the business of the Partnership, we will reimburse PAA s general partner for all reasonable costs and expenses incurred by it in connection with the performance of these services and will also reimburse PAA s general partner for any sales, use, excise, value added or similar taxes incurred by it in connection with the provision of the services and all insurance coverage expenses it incurs or payments it makes with respect to our assets.

The omnibus agreement will also provide that PAA s general partner will provide specified employees to our general partner to provide our general partner with those services necessary to operate, manage, maintain and report the operating results of the Partnership s assets. Such employees will be under the direction, supervision and control of our general partner and our general partner will reimburse PAA s general partner for all costs and expenses incurred by it in connection with the employees.

The omnibus agreement can be amended by written agreement of all the parties to the agreement. However, the partnership may not agree to any amendment or modification that would, in the reasonable discretion of our general partner, be adverse in any material respect to the holders of our common units without the prior approval of the conflicts committee.

Except for the indemnification provisions set forth in the agreement, the omnibus agreement will terminate if PAA ceases to directly or indirectly control our general partner or us or may be terminated by PAA if PNGS GP LLC is removed as our general partner under circumstances where cause does not exist and the common units held by PAA and its affiliates were not voted in favor of such removal.

Tax Sharing Agreement

Concurrently with the closing of our initial public offering, we will enter into a tax sharing agreement with PAA, pursuant to which we and PAA will agree on the method of allocation among us and our subsidiaries, on the one hand, and PAA and its subsidiaries (other than us and our subsidiaries) on the other, of the responsibilities, liabilities and benefits relating to any taxes for which a combined return is filed for taxable periods including or beginning on the closing date of this offering.

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Related Party Transactions

Potential PAA Financial Support

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA s ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. In that regard, the following forms of potential PAA financial support will be deemed fair to our unitholders, and will not constitute a breach of any duty by our general partner, if consummated on terms not less favorable than those described below:

- our issuance of common units to PAA at a price per common unit of no less than 95% of the trailing 20-day average closing price per common unit.

- our borrowing funds from PAA on terms that include a tenor of no more than three years and a fixed rate of interest that is no more than 100 basis points higher than the lesser of (i) the fixed rate of interest incurred by PAA on any senior notes or other financial instruments issued by PAA to fund such loan to us or (ii) the weighted average of PAA s outstanding senior note issues.

- PAA may provide us or any of our subsidiaries with guaranties or trade credit support to support the ongoing operations of us or our subsidiaries; *provided*, *that* (i) the pricing for any such guaranties or trade credit support is no more than the cost to us of issuing a comparable letter of credit under our credit agreement, and (ii) any such guaranties or trade credit support are limited to ordinary course obligations of us or our subsidiaries and do not extend to indebtedness for borrowed money or other obligations that could be characterized as debt.

We have no obligation to seek financing or support from PAA on the terms described above or to accept such financing or support if offered to us. In addition, PAA will have no obligation to provide financial support under these or any other circumstances. We would anticipate that PAA would provide such support to us only if permitted under the relevant provisions of its debt instruments at the time. Finally, the existence of these provisions will not preclude other forms of financial support from PAA, including financial support on significantly less favorable terms if we conclude that such support is in, or not opposed to, our best interests.

In addition, following the completion of our issuance of common units in connection with an underwritten public offering, direct placement and/or private offering of common units, we may make a reasonably prompt redemption of a number of common units owned by PAA that is no greater than the aggregate number of common units issued to PAA pursuant to the first bullet above (taking into account any prior redemptions pursuant to this paragraph) at a price per common unit that is no greater than the price per common unit paid by the investors in such offering or placement, as applicable, less underwriting discounts and commissions or placement fees, if any. As with the transactions described in the bullets above, any such redemptions will be deemed fair to our unitholders and will not constitute a breach of any duty of our general partner.

Intercompany Note with PAA

In conjunction with the PAA Ownership Transaction, all third party debt was terminated and replaced with a related party note payable to PAA with an initial principal amount of approximately $438 million and a fixed interest rate of 6.5%. The note is a demand note with no set maturity date and under which PAA has the ability to demand payment at any time. However, PAA has issued a waiver stating that it will not demand payment during the year ended

December 31, 2010, and PAA has indicated that it will not request repayment prior to December 31, 2013. The interest on the note is paid in-kind and added to the principal amount of the note. As of December 31, 2009, amounts due under the note were approximately $451 million, including accrued interest. To the extent necessary, we have the ability to incur additional borrowings under the note. Upon closing of this offering, we intend to use the net proceeds from this offering, together with borrowings under our credit facility, to repay approximately $433.9 million of the intercompany note. We expect that any intercompany indebtedness not repaid in connection with this offering will be extinguished and treated as a capital contribution and part of PAA s investment in us.

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Contracts with Affiliates

In December 2008, PAA made a $600,000 loan to Dean Liollio, President of PAA s natural gas storage business, to assist him with the payment of relocation expenses incurred in connection with his employment with PAA s general partner. The loan did not bear any interest and has since been repaid in full.

Review, Approval or Ratification of Transactions with Related Persons

We expect that we will adopt policies for the review, approval and ratification of transactions with related persons similar to those that have been adopted by PAA, as embodied in PAA s Governance Guidelines and Code of Business Conduct.

Upon our adoption of Governance Guidelines similar to those of PAA, a director would be expected to bring to the attention of the CEO or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and the Partnership or our general partner on the other. The resolution of any such conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

If a conflict or potential conflict of interest arises between the Partnership and our general partner, the resolution of any such conflict or potential conflict should be addressed by the board in accordance with the provisions of the Partnership Agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under the Partnership Agreement.

Upon our adoption of a Code of Business Conduct similar to PAA s, any Executive Officer will be required to avoid conflicts of interest unless approved by the board of directors.

In the case of any sale of equity by the Partnership in which an owner or affiliate of an owner of our general partner participates, we anticipate that our practice will be to obtain approval of the board for the transaction. We anticipate that the board will typically delegate authority to set the specific terms to a pricing committee, consisting of the CEO and one independent director. Actions by the pricing committee will require unanimous approval.

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CONFLICTS OF INTEREST AND FIDUCIARY DUTIES

Conflicts of Interest

Potential conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates, including PAA, on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have legal duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a legal duty to manage our partnership in a manner beneficial to us and our unitholders. It is not possible to predict the nature or extent of these potential future conflicts of interest at this time, nor is it possible to determine how we will address and resolve any such future conflicts of interest. The resolution of these conflicts may not always be in the best interest of our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner s board of directors or its conflicts committee will resolve, on behalf of our public unitholders, that conflict. Our partnership agreement contains provisions that define and limit our general partner s duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might be challenged as breaches of its fiduciary duty.

Our partnership agreement provides that any resolution or course of action adopted by our general partner in respect of a conflict of interest will be permitted and deemed approved by all of our partners, and will not constitute a breach of our partnership agreement or any duty stated or implied by law or equity if the resolution or course of action in respect of such conflict of interest is fair and reasonable to us. Such resolution will be deemed fair and reasonable if:

- approved by the conflicts committee of our general partner after due inquiry, based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us (although our general partner is not obligated to seek such approval);

- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates, directors and executive officers;

- determined by our general partner (after due inquiry) to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

- approved by our general partner (after due inquiry), based on a subjective belief that the course of action or determination that is the subject of such approval is fair and reasonable to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith. Under our partnership agreement, a determination made in good faith means that the person making the determination does so with the subjective belief that the determination (i) with respect to matters involving us, is in, or not opposed to, the best interests of our partnership and (ii) with respect to matters involving the relative rights and privileges of holders of our equity interests, consistent with the intent of the provisions of our partnership agreement. In connection therewith, such person or persons may take into account the circumstances and relationships involved (including our short-term or long-term interests and other arrangements or relationships that could be considered favorable or advantageous to us). When our partnership agreement requires someone to act after due inquiry, the person or persons making such determination or taking or declining to take an action subjectively believe that such person or persons had available adequate information to make such determination or to take or decline to take such action in accordance with the applicable contractual standard.

Our partnership agreements also provides that, to the fullest extent permitted by law, in connection with any action or inaction of, or determination made by, our general partner s board of directors or its conflicts committee with respect to any matter relating to us, it shall be presumed that our general partner s board of

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directors or its conflicts committee acted in a manner that satisfied the contractual standards set forth in our partnership agreement, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or our partnership challenging any such action or inaction of, or determination made by, our general partner, the person bringing or prosecuting such proceeding shall have the burden of overcoming such presumption.

Potential for Conflicts

Conflicts of interest could arise in the situations described below, among others.

Neither our partnership agreement nor any other agreement requires PAA to pursue a business strategy that favors us or utilizes our assets or dictates what markets to pursue or grow. Directors of the ultimate general partner of PAA have a fiduciary duty to make these decisions in the best interests of the owners of PAA, which may be contrary to our interests.

Because certain of the directors of our general partner are also directors and/or officers of PAA s general partner, such directors have fiduciary duties to PAA that may cause them to pursue business strategies that disproportionately benefit PAA or which otherwise are not in our best interests.

Our general partner and its affiliates are allowed to take into account the interests of parties other than us in resolving conflicts of interest.

Our partnership agreement contains provisions that 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. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples include our general partner s limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership.

Certain of the executive officers of our general partner will devote a substantial portion of time to the business of PAA and will be compensated by PAA accordingly.

Certain of the executive officers of our general partner are also executive officers of PAA s general partner, including Greg L. Armstrong, Harry N. Pefanis, Al Swanson and Tina L. Summers, and will devote a substantial portion of their time to PAA s business and affairs. We will also utilize a significant number of employees of PAA to operate our business and for which we will reimburse PAA under the omnibus agreement for expenses of operational personnel who perform services for our benefit and for allocated general and administrative expenses. Please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Omnibus Agreement. Our general partner and PAA will also conduct businesses and activities of their own in which we will have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the executive officers of our general partner.

PAA may engage in competition with us.

While PAA has stated that it intends to utilize our partnership as the primary vehicle through which it will participate in the natural gas storage business, PAA and its affiliates are not limited in their ability to compete with us.

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

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval or with respect to which our general partner has sought conflicts committee approval, on such terms as it determines to be necessary or appropriate to conduct our business including, but not limited to, the following:

the making of any expenditures, the lending or borrowing of money, the assumption or guarantee of or other contracting for, indebtedness and other liabilities, the issuance of evidences of indebtedness, including indebtedness that is convertible into our securities, and the incurring of any other obligations;

the purchase, sale or other acquisition or disposition of our securities, or the issuance of additional options, rights, warrants and appreciation rights relating to our securities;

the mortgage, pledge, encumbrance, hypothecation or exchange of any or all of our assets;

the negotiation, execution and performance of any contracts, conveyances or other instruments;

the distribution of our cash;

the selection and dismissal of employees and agents, outside attorneys, accountants, consultants and contractors and the determination of their compensation and other terms of employment or hiring;

the maintenance of insurance for our benefit and the benefit of our partners;

the formation of, or acquisition of an interest in, the contribution of property to, and the making of loans to, any limited or general partnership, joint venture, corporation, limited liability company or other entity;

the control of any matters affecting our rights and obligations, including the bringing and defending of actions at law or in equity, otherwise engaging in the conduct of litigation, arbitration or mediation and the incurring of legal expense, the settlement of claims and litigation;

the indemnification of any person against liabilities and contingencies to the extent permitted by law;

the making of tax, regulatory and other filings, or the rendering of periodic or other reports to governmental or other agencies having jurisdiction over our business or assets; and

the entering into of agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Our partnership agreement provides that our general partner must act in good faith when making decisions on our behalf, and our partnership agreement provides that in order for a determination to be made in good faith with respect to matters involving us, our general partner must subjectively believe that the determination is in, or not opposed to, our best interests. Please read The Partnership Agreement Voting Righ