PAA NATURAL GAS STORAGE LP
Form 10-K
February 29, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

or

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

Commission file number 1-34722

PAA Natural Gas Storage, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**27-1679071**

(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1500, Houston, Texas	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

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

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

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

None

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

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

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

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

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

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

Large accelerated Filer	¨	Accelerated Filer	x
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller Reporting Company	¨

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $695 million on June 30, 2011, based on a closing price of $22.67 per Common Unit as reported on the New York Stock Exchange on such date.

At February 22, 2012, there were outstanding 59,193,825 Common Units.

DOCUMENTS INCORPORATED BY REFERENCE

NONE

PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

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FORWARD-LOOKING STATEMENTS

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- significantly reduced volatility and/or lower spreads in natural gas markets for an extended period of time;
- factors affecting demand for natural gas storage services and the rates we are able to charge for such services, including the balance between the supply of and demand for natural gas;
- our ability to maintain or replace expiring storage contracts, or enter into new storage contracts, in either case at attractive rates and on otherwise favorable terms;
- factors affecting our ability to realize revenues from hub services and merchant storage transactions involving uncontracted or unutilized capacity at our facilities;
- the effects of competition;
- the impact of operational, geologic and commercial factors that could result in an inability on our part to satisfy our contractual commitments and obligations, including the impact of equipment performance, cavern operating pressures, cavern temperature variances, salt creep and subsurface conditions or events;
- risks related to the ownership, development and operation of natural gas storage facilities;
- failure to implement or execute planned internal growth projects on a timely basis and within targeted cost projections;
- the effectiveness of our risk management activities;
- operational, geologic or other factors that affect the timing or amount of crude oil and other liquid hydrocarbons that we are able to produce in conjunction with the operation of our Bluewater facility;
- market or other factors that affect the prices we are able to realize for crude oil and other liquid hydrocarbons produced in conjunction with the operation of our Bluewater facility;
- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns;

the successful integration and future performance of acquired assets or businesses;

our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;

our ability to obtain and/or maintain all permits, approvals and authorizations that are necessary to conduct our business and execute our capital projects;

shortages or cost increases of supplies, materials or labor;

weather interference with business operations or project construction;

our ability to receive open credit from our suppliers and trade counterparties;

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- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

- the operations or financial performance of assets or businesses that we acquire;

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- increased costs or unavailability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plan; and

- other factors and uncertainties inherent in the ownership, development and operation of natural gas storage facilities.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. See Item 1A. Risks Factors. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

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PART I

Items 1 and 2. *Business and Properties*

General

PAA Natural Gas Storage, L.P. is a Delaware limited partnership formed by Plains All American Pipeline, L.P. (PAA) on January 15, 2010. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K and unless the context indicates otherwise, the terms Partnership, PNG, we, us, our, ours and similar terms refer to PAA Natural Gas Storage, L.P. and its subsid

Our business consists of the acquisition, development, ownership, operation and commercial management of natural gas storage facilities. As of December 31, 2011, we owned and operated three natural gas storage facilities located in Louisiana, Mississippi and Michigan. 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.

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.

Organizational History

We were formed as a limited partnership to own, operate and grow the natural gas storage business of PAA, in which it acquired its initial interest in 2005. Our 2% general partner interest is held by PNGS GP LLC, a Delaware limited liability company, whose sole member is PAA. References to our general partner, as the context requires, include only PNGS GP LLC.

Partnership Structure and Management

At December 31, 2011, PAA owned an aggregate direct and indirect 64% ownership interest in us comprised of the general partner s 2% interest, 28.3 million common units, 11.9 million Series A subordinated units and 13.5 million Series B subordinated units, as well as incentive distribution rights. The Series B subordinated units are not 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.

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The diagram below illustrates the structure of PAA Natural Gas Storage, L.P. at February 22, 2012.

(1) Incentive Distribution Rights (IDRs). See Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities for discussion of our general partner s IDRs.

PNGS GP LLC, our general partner, has sole responsibility for conducting our business and for managing our operations. We have entered into an omnibus agreement with PAA and certain of its affiliates, which governs 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. See Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance and Item 13. Certain Relationships and Related Transactions, and Director Independence Related Party Transactions Omnibus Agreement.

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

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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 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.* Our primary commercial objective is to generate a significant portion of our revenues by committing a high percentage of our storage capacity under firm multi-year storage contracts. 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. Commercially, and operationally, we routinely seek to optimize our profitability by executing various initiatives that increase our efficiency, reliability and flexibility.

- *Through our dedicated commercial marketing group, using a portion of our storage capacity in conjunction with our commercial marketing activities to enhance our margins.* Similar to the business model 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 with third parties, we have a dedicated commercial marketing group that captures market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities.

- *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. We currently have permitted expansion activities underway at each of our three facilities. Taking into account expansions that are currently under construction and permitted expansions not yet under construction, we have the potential to increase our capacity from approximately 76 billion cubic feet (Bcf) of working capacity at December 31, 2011 to an aggregate of approximately 149 Bcf of working capacity at these three facilities.

- *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 seek acquisition or development opportunities that will be accretive (i.e. 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.

- *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.

Our Financial Strategy

An important factor 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 sustain our current distribution as well as 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 to 4.0x (Adjusted EBITDA is earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan expense, 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.

In order for us to maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for future expansion projects (beyond the projects currently under development), as well as future acquisitions, through a combination of equity capital and cash flow in excess of distributions. From time to time, we may be outside the parameters of our targeted credit profile due to challenging market conditions, 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.

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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, we believe this credit profile should provide flexibility during periods where storage markets become oversupplied and thus position us to take advantage of attractive acquisition opportunities.

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 Item 1A. Risk Factors Risks Related to Our Business The credit and risk profile of our general partner and its owner, PAA, could adversely affect our credit and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

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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, Southern Pines and Bluewater storage facilities are strategically positioned relative to several major market hubs and have extensive pipeline header systems that are interconnected directly or indirectly with multiple large-diameter interstate and intrastate pipelines. These facilities enable us to serve a variety of major producing regions and LNG importers or exporters, as well as the primary consumer and industrial markets in the Gulf Coast, Midwest, Northeast and Southeast. In the aggregate, our three facilities have peak injection and withdrawal capacity of 4.1 Bcf per day and 6.4 Bcf per day, respectively.

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. 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.

Our dedicated commercial marketing group enhances our margins. Our dedicated commercial marketing group has the capability to capture short-term opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities. Through this group, we have a consistent presence in our markets that enhances our ability to properly price our long and short term storage offerings while positioning us to capitalize on volatility and inefficiency in natural gas markets. We conduct activities in our commercial marketing group within pre-defined risk parameters, and our general policy is (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 business and to structure our transactions so that commodity price fluctuations will not have a material adverse impact on our cash flows 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 Gulf Coast storage facilities have the ability to be significantly expanded at competitive costs and with a relatively high degree of schedule certainty. 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 and Southern Pines facilities (Gulf Coast Facilities) significantly beyond their current size. In addition, because the existing infrastructure at both of these facilities has been specifically designed to facilitate future expansion, as we expand these facilities we expect 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.

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 and our predecessor have been involved in substantially all aspects of the natural gas storage business since 2005 and our operational and management teams have extensive energy industry and acquisition experience.

We have the financial flexibility to pursue acquisition and expansion opportunities. 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 management team with extensive knowledge of natural gas storage operations 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. Through their indirect and direct interests in us, our general partner and PAA, our general partner s executive and senior management team has a significant, vested interest in our continued success.

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

Our Relationship with PAA

We believe one of our strengths is our relationship with PAA, which is one of the largest publicly-traded master limited partnerships as measured by its equity market capitalization of approximately $11.4 billion as of December 31, 2011. 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, natural gas liquids and liquefied petroleum gas and other natural gas-related petroleum products. PAA s assets include approximately 16,000 miles of pipelines, approximately 100 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 in excess of 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 $15 billion and increased the annualized distribution on its limited partner units by over 125%, from $1.80 per unit as of PAA s initial public offering to $4.10 per unit for the distribution paid in February 2012.

Our partnership owns all of the natural gas storage business and assets formerly owned by PAA through a joint venture with Vulcan Energy 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. As the ultimate owner of our 2% general partner interest, all of our incentive distribution rights and an approximate 62% limited partner interest in us (including common units, Series A subordinated units and Series B subordinated units), PAA has a significant economic stake in us and is motivated to promote and support the successful execution of our growth plan and strategy.

We have also entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which PAA s general partner has agreed to provide us with certain general and administrative services and employees, and we have agreed to reimburse PAA s general partner for the costs of such services.

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 enhances our ability to grow our business.

Recent Developments

Modification of Terms of Series B Subordinated Units

In February 2012, we modified the terms of the Partnership s 13.5 million Series B subordinated units, which modification was approved by PAA, the owner of all of the Series B subordinated units. The Partnership s Series B subordinated units do not participate in quarterly distributions. Instead, the Series B subordinated units convert into Series A subordinated units or common units in five distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in our quarterly distributions. The modification increases the quarterly distribution benchmark for the first three of the five tranches, totaling 7.5 million Series B subordinated units in the aggregate, to an annualized level of $1.71 per unit. Previously, the quarterly distribution levels required to cause conversion for these three tranches were at annualized levels of $1.44, $1.53 and $1.63 per unit. The modification, which was made in recognition of the continued challenging market conditions facing the natural gas storage business, benefits our common unitholders by reducing the number of units on which distributions would otherwise be required to be paid in the case of distributions below the annualized level of $1.71.

Natural Gas Market Overview

North American natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions. 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 and on a long term basis, 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 the value of storage services. On a short term basis, storage demand and values are also significantly influenced by operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials.

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Natural Gas Demand. During the period from 2001 through 2011 domestic natural gas consumption has grown, albeit unevenly, driven primarily by growth in the seasonal and weather-sensitive electric power generation and commercial sectors, offset by declines in the residential and industrial sectors. The chart below, based on U.S. Energy Information Administration (EIA) data and forecasts, shows the overall growth in consumption (and the disposition of such growth) for the eleven year period ended October 2011. The chart also includes EIA forecasted data for December 2011.

Natural Gas Supply. For a number of years during the last decade, domestic natural gas production was relatively flat and failed to keep pace with domestic consumption. Over the past several years, however, domestic natural gas production has been growing rapidly. This trend reversal is primarily due to increases in production from developing shale resource plays. According to EIA data, domestic production of natural gas increased by 5.4% during the three year period from January 1, 2009 through December 31, 2011.[1] EIA forecasts also predict that shale gas production will increase 229% from 2009 to 2035.

Market Balance and Volatility. The seasonality of natural gas has remained strong during the last decade, with consumption during the peak winter months averaging approximately 40% more than consumption during the summer months, per EIA data. For the lower 48 states, from January 1, 2011 to December 31, 2011, U.S. consumption reached peak use of more than 115 Bcf on February 10, while the lowest daily consumption during this same period was approximately 48 Bcf on October 9, per EIA and other published daily data sources. On the other hand, daily U.S. production in the lower 48 during this same twelve month period ranged from 61 Bcf to 71 Bcf. Natural gas storage (and to a lesser extent imported natural gas from Canada) served as the shock absorber that balanced the market, serving as a source of supply to meet the consumption demands in excess of daily production capacity and a warehouse for gas production in excess of daily demand during low demand periods. This seasonal consumption pattern is a major driver of demand for gas storage and the price difference, or spread, between the summer and winter season provides a proxy for the fundamental value of storage.

During most of the past decade, this strong seasonal trend has produced seasonal spreads that have generally moved within a range of approximately $0.37-$4.75 per MMBtu, with the high end of that range occurring during the 2006-2007 timeframe. However, in 2011 the seasonal spreads (Oct-Jan) traded in a range of approximately $0.37-$0.62. In addition, lower short term spreads and basis differentials have reduced overall market volatility, which negatively impacts storage demand and value. While there are a variety of factors that have contributed to these softer market conditions, we believe the key drivers are (i) relatively flat natural gas consumption over the last year and projected flat consumption for the next several years, (ii) increased natural gas supplies due to production from shale resources, (iii) net increases in storage capacity, and (iv) lower basis differentials due to expansion of natural gas transportation infrastructure in the U.S. over the last five years.

1 Reported production per EIA was used through October 2011. For November and December 2011 reported production volume from November and December 2010 were used as proxies, respectively, for the final two months of 2011.

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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 based on capacity additions and in response to significant variations in natural gas supply and demand.

According to EIA data and as indicated in the chart below, peak storage utilization as a percentage of peak storage capacity has ranged from 91% in 2005 to 99% in 2009 and decreased to 94% in 2011, in part due to a 5.5% increase in peak capacity relative to 2009 levels. Despite the increase in storage capacity, storage inventories, as reported by the EIA, reached a record peak level of 3.852 Tcf in November of 2011.

	Non Coincident Peak Capacity (TCF)	Max Inventory in Storage (TCF)	Peak Utilization
2005	3.600	3.282	91%
2006	3.609	3.461	96%
2007	3.703	3.545	96%
2008	3.789	3.488	92%
2009	3.889	3.837	99%
2010	4.049	3.840	95%
2011	4.103	3.852	94%

While it is difficult to predict when, and how much, new capacity will be added to the market in the next few years, we believe that certain of the supply and demand factors contributing to the current softness in the storage market (i.e., robust supply levels, low levels of natural gas demand growth and reduced price volatility) are cyclical and self correcting over time, and that the long term outlook for storage utilization and demand is positive.

Our Assets

As of December 31, 2011 we owned a 100% interest in three natural gas storage facilities. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt-cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Given the relative proximity of these two facilities to each other and the extent of direct and indirect connecting pipelines, we use a combination of interruptible storage services and third party transportation services to coordinate movements between and optimize the performance of these two Gulf Coast facilities. Our third facility is our Bluewater facility, 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 salt-cavern and depleted reservoir storage facilities as of December 31, 2011 (working gas capacity figures in the table below are based on assumed base gas levels, which may vary by facility based on commercial activities and other factors):

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Facility Type (Names)	Working Gas Capacity (Bcf)	Peak Injection Rate (Bcf/d)	Peak Withdrawal Rate (Bcf/d)	Compression (Horsepower)
Salt-caverns (Pine Prairie and Southern Pines)				
Total Existing	50	3.6	5.6	119,000
Total Permitted	120	3.6	5.6	146,500
Depleted Reservoirs (Bluewater)				
Total Existing	26	0.5	0.8	13,350
Total Permitted	29	0.5	0.8	13,350
Grand Total Existing (all facilities)	76	4.1	6.4	132,350
Grand Total Permitted (all facilities)	149	4.1	6.4	159,850

Salt Cavern Storage Facilities. We own two FERC regulated, high deliverability salt cavern natural gas storage facilities located on the Gulf Coast. Our Pine Prairie facility is located in Evangeline, Rapides and Acadian Parishes, Louisiana and is permitted for up to 80 Bcf of working gas capacity, which includes 32 Bcf of incremental capacity that was recently approved by the FERC subject to the requirement that Pine Prairie conduct an open season in accordance with applicable FERC policy. Our Southern Pines facility is located in Greene County Mississippi and is permitted for up to 40 Bcf of working gas capacity. These two facilities had an aggregate working gas capacity as of December 31, 2011 of approximately 50 Bcf. During 2012, we anticipate placing an additional 16 Bcf of working gas capacity in service at these facilities, which will include a fifth cavern at Pine Prairie that is scheduled to be placed into service in the second quarter of 2012, a fourth cavern at Southern Pines that is scheduled to be placed into service in the third quarter of 2012 and additional capacity at both facilities from incremental leaching activities.

Both of these facilities are strategically-located and have 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 (the delivery point for New York Mercantile Exchange (NYMEX) natural gas futures contracts and located approximately 50 miles southeast of Pine Prairie), the Carthage Hub (located in East Texas), and the Perryville Hub (located in North Louisiana), and to existing and proposed LNG import and export facilities.

Pine Prairie s pipeline header system, which includes an aggregate of approximately 80 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. Pine Prairie s peak daily injection and withdrawal rates are 2.4 Bcf and 3.2 Bcf, respectively, and Pine Prairie has a total of 71,000 horsepower of compression capacity currently in service with another 27,500 horsepower of permitted capacity.

Southern Pines pipeline header system, which includes an aggregate of 60 miles of 24-inch diameter pipe, is directly or indirectly connected to 8 major natural gas pipelines servicing the Gulf Coast, Northeast, Mid-Atlantic and Southeastern U.S. markets. Southern Pines peak daily injection and withdrawal rates are 1.2 Bcf and 2.4 Bcf, respectively, and Southern Pines has a total of 48,000 horsepower of compression capacity currently in service.

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. Bluewater s peak daily injection and withdrawal rates are 0.5 Bcf and 0.8 Bcf, respectively.

As indicated in the table above, Bluewater has total working gas storage capacity of approximately 26 Bcf in two depleted reservoirs and is permitted for an additional 3 Bcf of working gas storage capacity. We expect to increase Bluewater s working gas capacity by 2 Bcf ratably over a 8 to 9-year period in connection with an ongoing 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. Bluewater has filed an application with the FERC to build a 20-inch pipeline that will be permitted for up to 300 MMcf per day and will connect its facility to a Canadian pipeline owned by an affiliate of Spectra Energy. The proposed pipeline is intended to replace a 12-inch pipeline that is permitted for up to 250 MMcf per day and is currently leased from Nova Chemical through January 2013. See Item 1A, Risk Factors Risks Related to our Business We may not receive the permits needed to complete construction of a pipeline that will replace the leased line that currently connects our Bluewater facility to markets in western Ontario.

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 FERC rate-making policies which currently permit our facilities to charge market-based rates for our services.

We generate revenue primarily from the provision of fee-based gas storage services to our customers. For the year ended December 31, 2011, our total net revenues (total revenues less storage related costs, the cost of natural gas sold and fuel expense) were derived approximately 91% from fee-based storage activities (which includes system access fees collected at our Pine Prairie facility), approximately 7% from the activities of our dedicated marketing group and approximately 2% from other activities, which includes the sale of liquid hydrocarbons incidentally produced in connection with the operation of our depleted reservoir storage facilities at Bluewater and other fuel and derivative related net gains and losses. We categorize the majority of the revenue we generate as being derived from Firm Storage Services or Hub Services and Merchant Storage Activities. We also generate a portion of our net revenues from other sources as described below in Other Activities.

Firm Storage Services.
The majority of our net revenue from firm storage services is derived from contracts with initial terms that generally range from one year to 10 years in length and pursuant to which customers receive the assured or firm right to store gas in our facilities. 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. As of December 31, 2011, the weighted average remaining tenor of our existing portfolio of third party firm storage contracts was approximately 3.3 years. Firm storage services revenue also includes, when applicable, cycling fees based on the volume of natural gas nominated for injection and/or withdrawal, as well as a small portion of natural gas nominated for injection that we retain as compensation for our fuel use. Storage related costs consist of fees incurred to lease third-party storage and pipeline capacity and certain other costs we may incur. Additionally, we incur fuel expense at our facilities as we manage injection and deliverability capacity. For the year ended December 31, 2011, net revenue from firm storage services (firm storage services revenues net of applicable storage related costs and fuel expense) comprised approximately 85% of our total net revenues.

Hub Services and Merchant Storage Activities.
We also generate net revenue from the provision of hub services at our facilities and through the merchant storage activities of our commercial marketing group, which captures short term market opportunities by utilizing a portion of our storage capacity and engaging in related commercial marketing activities.

Our capacity to provide hub services is primarily dependent on our outstanding obligations to customers under firm storage services contracts. As a result, increases in our firm storage services obligations may limit our ability to provide hub services and vice versa. 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) 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. A portion of our revenues related to these activities may include fuel collections.

Our merchant storage activities generate revenue through the hedged purchase and sale of natural gas net of any storage related costs incurred. We utilize physical storage at our facilities and derivatives to hedge expected margin from these activities. Through these transactions, we 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 is (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

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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.

In connection with our hub services and merchant storage activities, we incur certain storage related costs. These costs consist of fees incurred to lease third-party pipeline capacity and storage and transaction costs associated with managing injection and deliverability capacity at our facilities. Costs associated with our leased pipeline capacity are subject to variation as the terms of these agreements typically contain certain fees which fluctuate based on actual volumes shipped in addition to monthly reservation fees. Also included in our storage related costs is fuel expense we incur as part of our short term activities.

For the year ended December 31, 2011, net revenue from hub services and merchant storage (hub services and natural gas sales revenues net of applicable storage related costs, fuel expense and the cost of natural gas sold) comprised approximately 12% of our total net revenues.

Other Activities.
We also generate revenue through certain fixed access fees collected at Pine Prairie and through the sale of crude oil and natural gas 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 to operate facilities and reflect any gain or loss on such sales as a part of other revenues. For the year ended December 31, 2011, net revenue from such other activities comprised approximately 3% of our total net revenues.

Overall, 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.

Customers

As of December 31, 2011, Southern Pines had 15 customers with firm storage contracts and 33 customers with hub services contracts, Pine Prairie had 21 customers with firm storage contracts and 59 customers with hub services contracts and Bluewater had 13 customers with firm storage contracts and 75 customers with hub services contracts. Approximately 17% of our total revenues for the year ended December 31, 2011 was generated from physical sales of natural gas executed through Natural Gas Exchange Inc., a commodity exchange. No other customer accounted for greater than 10% of our total revenues for the year ended December 31, 2011.

Contracts

See Our Operations.

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 and Southern Pines compete 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 and Southern Pines, while Bluewater competes with several Midwest utility and pipeline storage providers.

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Natural Gas Regulation

PNG is 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 market participants. The failure to comply with such laws and regulations can result in substantial penalties and fines. The regulatory burden increases our cost of doing business and, consequently, affects our profitability. 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. We do not believe that we are affected by applicable laws and regulations in a significantly different manner than are our competitors.

The following is a summary of the kinds of regulation that may impact our operations. However, our unitholders should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Our facilities provide natural gas storage services in interstate commerce and are subject to comprehensive regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (NGA). Pursuant to the NGA and FERC regulations, storage providers are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. The terms and conditions for services provided by our facilities are set forth in FERC approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand.

The FERC also has authority over the siting, construction, and operation of U.S. pipeline transportation and storage facilities and related facilities used in the transportation, storage and sale for resale of natural gas in interstate commerce, including the extension, enlargement or abandonment of such facilities. The FERC s authority extends to maintenance of accounts and records, terms and conditions of service, 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. Our natural gas storage entities are required by the FERC to post certain information daily regarding customer activity, capacity and volumes on their respective websites. Additionally, the FERC has jurisdiction to impose rules and regulations applicable to all natural gas market participants including PNG Marketing and PAA Natural Gas Canada, to ensure market transparency. FERC regulations 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. Our facilities and marketing entities are subject to these annual reporting requirements.

Under the Energy Policy Act of 2005 (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 gives the FERC civil penalty authority 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.

Bluewater provides storage service by means of receipts or deliveries of natural gas at the international border with Canada or within the Province of Ontario. The importation and exportation of natural gas from and to the United States and Canada is subject to regulation by U.S. Customs and Border Protection, U.S. Department of Energy and the National Energy Board of Canada. Bluewater, PNG Marketing and PAA Natural Gas Canada have regulatory authorization to import and export natural gas from and to the Unites States and Canada.

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. New rules, orders, 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, orders, regulations or laws or the effect they could have on our business, financial condition, and results of operations or ability to make distributions to our unitholders.

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 imposes stringent limitations on the treatment, storage, transportation and disposal of hazardous 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. CERCLA also authorizes the Environmental Protection Agency (EPA) and, in some instances, third parties, to respond to threats to public health or the environment and seek recovery of response costs from 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.

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 result in significant 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.

Noise Emissions. The Partnership is subject to a number of federal, state and local laws, regulations, ordinances and standards that govern noise emissions from our facilities. The U.S. Occupational Safety & Health Administration (OSHA) has established maximum noise levels for occupational exposure and the Partnership undertakes various noise protection efforts, including administrative and engineering controls, in order to achieve these standards and protect our employees. The Partnership has also implemented a hearing conservation program for our employees who may be exposed to noise in the workplace and provides personal protective equipment as necessary.

The Partnership must also comply with federal guidelines and state and local regulations regarding sound that is transmitted from our facilities and our construction projects to the surrounding community. At the federal level, the EPA has identified a maximum sound level that will not adversely affect public health and welfare. Although allowed noise emission levels are typically established on a project by project basis and depend to a certain extent on pre-existing ambient noise levels for a given project, the FERC has adopted the EPA s maximum sound level as a general goal for new gas compressor stations, pipeline construction and other operations regulated by the FERC. In addition, sound generated from construction and operation of our facilities and pipelines is also regulated in some jurisdictions at the county and municipal level, and depending on the circumstances, such local requirements may be more or less stringent than applicable federal rules.

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Water Discharges. The Clean Water Act (CWA) and analogous state laws regulate 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 Program (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. In December 2009, the EPA published its findings that emissions of greenhouse gases (GHGs), including carbon dioxide and methane, present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth s atmosphere and other climatic changes. Based on these findings, in 2010 the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the CAA, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires construction and operating permit reviews for GHG emissions from certain large stationary sources, including, among others, onshore and offshore oil and natural gas production facilities. Also, Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states already have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. The adoption of any legislation or regulation that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for natural gas. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our 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, the Pipeline Safety Improvement Act of 2002, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, and, most recently, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011. These amendments, along with implementing regulations more recently adopted by PHMSA, 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.

On December 13, 2011, the United States Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the Act). The President signed the Act into law on January 3, 2012. Under the Act, maximum civil penalties for certain violations have been increased from $100,000 to $200,000 per violation per day, and from a total cap of $1 million to $2 million. In addition, the Act reauthorizes the federal pipeline safety programs of PHMSA through September 30, 2015, and directs the Secretary of Transportation to undertake a number of reviews, studies and reports, some of which may result in additional natural gas and hazardous liquids pipeline safety rulemaking. Some of these directives include:

The Secretary of Transportation must revise regulations establishing time limits for notification of pipeline facility accidents and incidents to a minimum of not more than 1 hour after discovery of an accident or incident;

Within 12 months, the Secretary of Transportation must submit to Congress a report providing information on the total number of authorized full-time positions for pipeline inspection and enforcement at the PHMSA, the total number of positions not filled, the action being taken to fill the vacant positions and any additional inspection and enforcement resource needs of the PHMSA;

Within 18 months, the Secretary of Transportation must conduct an evaluation to determine whether integrity management system requirements already in place for pipelines in High Consequence Areas (HCAs) should be expanded to pipelines beyond HCAs;

Within two years, the Secretary of Transportation must submit to Congress a report on the results of a review of existing federal and state regulations for gas and hazardous liquid gathering lines located offshore, including within inlets of the Gulf of Mexico, for the purpose of determining whether the Secretary should issue regulations subjecting offshore gathering lines to the same standards and regulations as other hazardous liquid gathering lines; and

Within two years, the Secretary of Transportation must determine whether to require the use of automatic or remote-controlled shut-off valves on new and entirely replaced transmission pipeline facilities.

A number of the provisions of the Act have the potential to cause owners and operators of pipeline facilities to incur significant capital expenditures and/or operating costs. Any additional requirements resulting from these directives are not expected to impact us differently than our competitors. We will work closely with our industry associations to participate with and monitor DOT-PHMSA s efforts.

In December 2009, PHMSA finalized a new rule dictating the shape and content of new control room management programs for hazardous liquid, gas transmission and distribution pipelines. The rule addresses human factors, including fatigue and other aspects of control room management for pipelines where controllers use supervisory control and data acquisition systems. The new rule became effective on February 1, 2010 and requires that control room management plans be written by August 1, 2011, which was completed on time by the Partnership. Implementation of certain aspects such as fatigue training for Controllers and Supervisors, Change Management, Operating Experience and establishing Shift Change procedures was required and completed by October 1, 2011. Implementation for the remaining aspects of the rule is required by August 1, 2012. We have already incorporated many of the new rule s requirements into our control room operations and we anticipate fully implementing the remaining provisions prior to the established deadline.

If approved by PHMSA, states may assume responsibility for enforcing federal interstate pipeline regulations as agents for PHMSA and conduct inspections of intrastate pipelines. In practice, states vary in their authority and capacity to address pipeline safety. We do not anticipate any significant issues in complying with applicable state laws and regulations.

The DOT has issued guidelines with respect to securing regulated facilities against terrorist attack. We have instituted security measures and procedures in accordance with such guidelines to enhance the protection of certain of our facilities. We cannot provide any assurance that these security measures would fully protect our facilities from an attack.

Occupational Safety and Health

Our operations are subject to a number of federal and state laws and regulations, including the federal 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.

Title to Properties and Rights-of-Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our major facilities are located are held by us (or entities in which we own an interest) pursuant to leases between us, 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. See Our Assets.

Insurance

We share insurance coverage with PAA and 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. In addition, the insurance policies are subject to deductibles that we consider reasonable and not excessive.

A natural gas storage facility, associated pipeline header system, and gas handling and compression facilities may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property, base gas, and equipment, pollution or environmental damage and suspension of operations. Our insurance does not cover every potential risk associated with operating natural gas storage facility, associated pipeline header system, and gas handling and compression facilities, including the potential loss of significant revenues. The overall trend in the insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

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. As of December 31, 2011, 83 full time employees of Plains All American GP LLC devoted substantially all of their time to carrying out our operations.

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Summary of U.S. Income Tax Considerations

The following is a brief summary of material tax considerations of owning and disposing of common units, however, the tax consequences of ownership of common units depends in part on the owner s individual tax circumstances. It is the responsibility of each unitholder, either individually or through a tax advisor, to investigate the legal and tax consequences, under the laws of pertinent U.S. federal, states and localities, of the unitholder s investment in us. Further, it is the responsibility of each unitholder to file all U.S. federal, state, provincial and local tax returns that may be required of the unitholder.

Partnership Status; Cash Distributions

We are treated for federal income tax purposes as a partnership based upon our meeting the Qualifying Income Exception imposed by Section 7704 of the Internal Revenue Code (the Code), which we must meet each year. The owners of our common units are considered partners in the Partnership so long as they do not loan their common units to others to cover short sales or otherwise dispose of those units. Accordingly, we are not liable for U.S. federal income taxes, and a common unitholder is required to report on the unitholder s federal income tax return the unitholder s share of our income, gains, losses and deductions. In general, cash distributions to a common unitholder are taxable only if, and to the extent that, they exceed the tax basis in the common units held.

Partnership Allocations

In general, our income and loss is allocated to the general partner and the unitholders for each taxable year in accordance with their respective percentage interests in the Partnership, as determined annually and prorated on a monthly basis and subsequently apportioned among the general partner and the unitholders of record as of the opening of the first business day of the month to which they relate, even though unitholders may dispose of their units during the month in question. In determining a unitholder s U.S. federal income tax liability, the unitholder is required to take into account the unitholder s share of income generated by us for each taxable year of the Partnership ending with or within the unitholder s taxable year, even if cash distributions are not made to the unitholder. As a consequence, a unitholder s share of our taxable income (and possibly the income tax payable by the unitholder with respect to such income) may exceed the cash actually distributed to the unitholder by us. Any time incentive distributions are made to the general partner, gross income will be allocated to the recipient to the extent of those distributions.

Basis of Common Units

A unitholder s initial tax basis for a common unit is generally the amount paid for the common unit and the unitholder s share of our nonrecourse liabilities (or liabilities for which no partner bears the economic risk of loss). A unitholder s basis is generally increased by the unitholder s share of our income and by any increases in the unitholder s share of our nonrecourse liabilities. That basis will be decreased, but not below zero, by the unitholder s share of our losses and distributions (including deemed distributions due to a decrease in the unitholder s share of our nonrecourse liabilities).

Limitations on Deductibility of Partnership Losses

The deduction by a unitholder of that unitholder s allocable share of our losses will be limited to the amount of that unitholder s tax basis in his or her common units and, in the case of an individual unitholder or a corporate unitholder who is subject to the at-risk rules (generally, certain closely-held corporations), to the amount for which the unitholder is considered to be at-risk with respect to our activities, if that is less than the unitholder s tax basis. A unitholder must recapture losses deducted in previous years to the extent that distributions cause the unitholder s at-risk amount to be less than zero at the end of any taxable year. Losses disallowed to a unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such unitholder s tax basis in his common units. Upon the taxable disposition of a common unit, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at-risk limitation but may not be offset by losses suspended by the basis limitation. Any loss previously suspended by the at-risk limitation in excess of that gain could no longer be used.

In addition to the basis and at-risk limitation described above, in the case of taxpayers subject to the passive loss rules (generally, individuals and certain closely held corporations), any partnership losses generated by us are only available to offset future income generated by us and cannot be used to offset income from other activities, including passive activities or investments. Any losses unused or suspended by virtue of the passive loss rules may be fully deducted if the unitholder disposes of all of the unitholder s common units in a taxable transaction with an unrelated party.

Section 754 Election

We have made the election provided for by Section 754 of the Code, which will generally result in a unitholder being allocated income and deductions calculated by reference to the portion of the unitholder s purchase price attributable to each asset of the Partnership.

Disposition of Common Units

A unitholder who sells common units will recognize gain or loss equal to the difference between the amount realized and the adjusted tax basis of those common units. A unitholder may not be able to trace basis to particular common units for this purpose. Thus, distributions of cash from us to a unitholder in excess of the income allocated to the unitholder will, in effect, become taxable income if the unitholder sells the common units at a price greater than the unitholder s adjusted tax basis even if the price is less than the unitholder s original cost. Moreover, a portion of the amount realized (whether or not representing gain) will 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, a unitholder may incur a tax liability in excess of the amount of cash the unitholder receives from the sale.

State, Local and Other Tax Considerations

In addition to federal income taxes, unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which a unitholder resides or in which we conduct business or own property. A unitholder may also be required to file state income tax returns and to pay taxes in various states. A unitholder may be subject to interest and penalties for failure to comply with such requirements. In certain states, tax losses may not produce a tax benefit in the year incurred (if, for example, we have no income from sources within that state) and also may not be available to offset income in subsequent taxable years. Some states may require us, or we may elect, to withhold a percentage of income from amounts to be distributed to a unitholder who is not a resident of the state. Withholding, the amount of which may be more or less than a particular unitholder s income tax liability owed to a particular state, may not relieve the unitholder from the obligation to file an income tax return in that state. Amounts withheld may be treated as if distributed to unitholders for purposes of determining the amounts distributed by us.

Our Canadian operations are conducted in an entity that is treated as a corporation for Canadian tax purposes (flow through for U.S. tax purposes.) Although we are subject to Canadian federal and provincial taxes, the impact to the year ended December 31, 2011 was immaterial.

Ownership of Common Units by Tax-Exempt Organizations and Certain Other Investors

An investment in common units by tax-exempt organizations (including IRAs and other retirement plans) and foreign persons raises issues unique to such persons. Virtually all of our income allocated to a unitholder that is a tax-exempt organization is unrelated business taxable income and, thus, is taxable to such a unitholder. A unitholder who is a nonresident alien, non-U.S. corporation or other non-U.S. person is regarded as being engaged in a trade or business in the United States as a result of ownership of a common unit and, thus, is required to file federal income tax returns and to pay tax on the unitholder s share of our taxable income. Finally, distributions to foreign unitholders are subject to federal income tax withholding at the highest applicable rate.

Available Information

We make available, free of charge on our Internet website (http://www.pnglp.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after we electronically file the material with, or furnish it to, the Securities and Exchange Commission (SEC).

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Item 1A. Risk Factors
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 existing distribution of $1.43 per unit or the minimum quarterly distribution of $1.35 per unit to holders of our common units and Series A subordinated units.

We may not have sufficient available cash from distributable cash flow each quarter to enable us to pay the existing distribution of $1.43 per unit or the minimum quarterly distribution of $1.35 per unit. 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;
- our ability to realize expected margins from our merchant storage activities due to natural gas price spreads and volatility levels, among other factors;
- regulatory action affecting the rates we can charge for the services we provide, the demand for natural gas, the supply of natural gas, our ability to expand our facilities, 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, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities.

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.

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 and as we bring on additional working capacity that is uncontracted. As of December 31, 2011, the weighted average remaining tenor of our existing portfolio of firm storage contracts, including binding precedent agreements, is approximately 2.4 years at Pine Prairie, approximately 1.9 years at Bluewater and approximately 5.5 years at Southern Pines. Over the last eighteen months, conditions in the gas storage market have deteriorated and the rates under certain of these contracts are higher than current market rates. The extension or replacement of existing contracts, and entering into new contracts, could be, and in some cases has already been, adversely impacted by a number of factors beyond our control, including:

an extended period of reduced natural gas price volatility;

a reduction in the difference between winter and summer prices on the natural gas futures market, sometimes referred to as the seasonal spread, due to real or perceived changes in supply and demand fundamentals;

a decrease in demand for natural gas storage in the markets we serve;

increased competition for storage in the markets we serve; and

higher interest rates, which increase inventory carrying costs for our customers.

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The failure to extend or replace a significant portion of our existing contracts, the extension or replacement of such contracts at unfavorable or lower rates, or the failure to enter into favorable contracts with respect to incremental working capacity, could have a material adverse effect on our business, financial condition, results of operations and ability to make 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 that 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 generally 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 we 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 740 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 provide natural gas storage services in interstate commerce, our natural gas storage facilities are subject to comprehensive regulation by the FERC under the NGA.

Pursuant to the NGA and FERC regulations, we are prohibited from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage or from maintaining any unreasonable difference in rates, charges, service, facilities, or in any other respect. Any successful complaint or protest against us could have an adverse impact on our revenues associated with providing storage services.

The terms and conditions for services provided by our facilities are set forth in FERC-approved tariffs. We have been granted market-based rate authorization for the services that our facilities provide. Market-based rate authority allows us to negotiate rates with individual customers based on market demand. A storage provider granted market-based rate authorization is required to notify FERC of significant changes occurring in its market power status, Significant changes include, but are not limited to, the storage provider expanding its storage capacity beyond the amount authorized in applicable certificate orders, the storage provider acquiring transportation facilities or additional storage capacity, an affiliate of the storage provider providing storage or transportation services in the same market area, and the storage provider or an affiliate acquiring an interest in or being acquired by an interstate pipeline.

Should we fail to comply with applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the EPAct 2005, FERC has civil penalty authority under the NGA to impose penalties for 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. See Items 1 and 2. Business and Properties Regulation.

Finally, new rules, orders, 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, orders, regulations or laws or the effect they could have on our business, financial condition, results of operations or ability to make distributions to our unitholders.

Our sales of natural gas, and related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission, the FERC and the Commodity Futures Trading Commission hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of natural gas and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC s regulations and policies, or with an interstate pipeline s tariff, could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

A prolonged period of stabilized natural gas prices and/or low levels of volatility 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 affects 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, due to a variety of factors (including relatively flat consumption over the last year, increased supplies due to shale production, net increases in storage capacity and lower basis differentials due to transportation infrastructure expansion), the volatility and seasonality of natural gas prices for the 12-18 months ended December 31, 2011 have been low relative to prior time periods. If these conditions persist, the demand for our services and the margin that we will be able to generate in connection with the sale of such services will remain under pressure and may decline.

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 such 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. This has been the case generally for the 12-18 months ended December 31, 2011, and if volatility and seasonality in the natural gas industry remain low relative to prior time periods, whether due to increased natural gas production or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline.

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. 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 customer s 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 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 facilities on economically viable terms.

Our 2012 expansion plans include the addition of 16 Bcf of working gas storage capacity at our Gulf Coast Facilities. These facilities are permitted for an aggregate of 120 Bcf of capacity, consisting of 80 Bcf at Pine Prairie and 40 Bcf at Southern Pines. In connection with our expansion efforts at these facilities, 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.

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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 facilities at Pine Prairie or Southern Pines. 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 receive the permits needed to complete construction of a pipeline that will replace the leased line that currently connects our Bluewater facility to markets in western Ontario.

Our Bluewater facility is connected to western Ontario markets through a leased pipeline that crosses the St. Clair river in Northern Michigan and connects to a pipeline owned by St. Clair Pipelines, an affiliate of Spectra Energy. Bluewater has been notified by the lessor of such pipeline that the lease will terminate in January 2013. Bluewater and an affiliate of Spectra Energy have entered into agreements to jointly construct a new line that will replace the existing line by January 2013. Construction of the replacement line requires FERC approval, a Presidential permit and approvals from applicable Canadian authorities. No assurances can be given that such approvals and permits will be received or that they will be received on a timely basis. Failure to receive such permits, or a significant delay in their receipt, could have a negative impact on Bluewater s ability to access markets in western Ontario, either through increased costs, lost business opportunities or both.

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. Although we have established credit policies that include assessing the creditworthiness of our customers 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:

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- 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;

- a failure on our part to create incremental storage capacity at our facilities due to reduced leaching rates, operational or other factors;

- the operating pressure of our storage facilities (affected in varying degree, depending on the type of storage cavern, by total volume of working and base gas, and temperature);

- 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 facilities 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.

Our cash receipts and financial results are usually lower in the second and third quarters of the calendar year, which may, depending on the level of our cash reserves, require us to borrow money in order to make distributions to the holders of our common units and Series A subordinated units.

Our cash expenditures related to our merchant storage activities are generally highest during summer months, and our cash receipts from such activities are highest during winter months. As a result, our results of operations for the summer are generally lower than for the winter. With lower cash flow during the second and third calendar quarters, depending on the level of our available cash reserves from prior quarters, we may be required to borrow money in order to pay distributions to the holders of our common units and Series A subordinated units.

Our marketing activities could result in financial losses. Our risk management policies cannot eliminate all risks and any non-compliance with our risk management policies could result in significant financial losses.

In 2010, we formed a dedicated commercial marketing group in order to capture short-term market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities. Through these transactions, we 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 is (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. Although we intend to conduct these transactions within these pre-defined risk parameters and we have risk management policies in place that are designed to manage and minimize commodity price and other risks, these policies will not eliminate all risks. We have in place risk management systems that are intended to quantify and manage risks, including risks related to our hedging activities such as commodity price risk and basis risk. We monitor processes and procedures to prevent unauthorized trading and to maintain substantial balance between purchases and future sales and delivery obligations. However, these steps may not detect and prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved. There is no assurance that our risk management procedures will prevent losses that would negatively affect our business, financial condition, results of operations and ability to pay distributions to the holders of our common units and Series A subordinated units.

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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 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 EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. 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. See Items 1 and 2. Business and Properties Natural Gas Regulation 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 due to the following:

- 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;

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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 our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources. 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.

Our natural gas storage facilities are relatively 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 have been designed to meet our contractual obligations with respect to wheeling, injection, withdrawal and gas specifications, the facilities are relatively 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;

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 or 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.

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

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of our credit facility could result in an event of default, which could enable our lenders, subject to the terms and conditions of the 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, see Item 7. 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.

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The credit and risk profile of our general partner and its owner, PAA, could adversely affect our credit 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 and risk profile.

If we were to seek a credit rating in the future, the 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.

An impairment of goodwill could reduce our earnings.

At December 31, 2011, we had approximately $325 million of goodwill. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the acquired tangible and separately measurable intangible net assets. U.S. generally accepted accounting principles, or GAAP, requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. If we were to determine that any of our goodwill was impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners equity and increase in balance sheet leverage as measured by debt to total capitalization.

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.

Pursuant to our partnership agreement, 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 our unitholders. 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 incur 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.

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 our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

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

Under Delaware law, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Our partnership agreement allows the general partner to incur obligations on our behalf that are expressly non-recourse to the general partner. The general partner has entered into such limited recourse obligations in most instances involving payment liability and intends to do so in the future.

In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

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 remove our general partner without its consent.

The unitholders will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove our general partner. PAA owns an aggregate of approximately 62% 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.

We may issue additional units without our unitholders approval, which would dilute our unitholders existing ownership interest.

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.

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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.

As of February 22, 2012, PAA owned 28,214,198 common units, 11,934,351 Series A subordinated units and 13,500,000 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, see Items 1A. Risk Factors 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.

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 a unitholder s detriment.

PAA owns and controls our general partner, as well as appoints 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.

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.

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.

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Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their units.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of 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 our unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation 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.

In addition, a change in current law may 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.

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

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.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, they will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax 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 technically 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. PAA owns 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 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. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder s allocable share of our net taxable income decrease the unitholder s tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price the unitholder receives is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if a unitholder sells units, the unitholder may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (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. Tax-exempt entities and non-U.S. persons should consult their 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 or debt service.

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 or debt service.

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

To maintain the uniformity of the economic and tax characteristics of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

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

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

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We 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. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which 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 or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

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.

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

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including 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 our unitholders do not live in any of those jurisdictions. Our unitholders 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, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in the states of Louisiana, Michigan and Mississippi. Each of these states currently imposes a personal income tax and also imposes 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 a unitholder s responsibility to file all U.S. federal, foreign, state and local tax returns.

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Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

In early December 2011, Pine Prairie received a property tax bill from Evangeline Parish, Louisiana for approximately $1.4 million that assessed taxes on property that Pine Prairie maintains is clearly exempt from tax pursuant to a 2006 tax abatement arrangement. In order to properly protest such tax assessment under Louisiana law, Pine Prairie was required to pay the disputed taxes by December 31, 2011 and file suit within 30 days thereafter. Pine Prairie paid the taxes under protest on December 29, 2011 and filed suit within the required 30 day period seeking recovery of the taxes based on the tax abatement arrangement. Pending resolution of the dispute, the taxes paid under protest are required to be held in a segregated account by Evangeline Parish and will be returned to Pine Prairie with interest when and if Pine Prairie prevails in the lawsuit. Except for such matter, 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, none of which we believe to be material.

Item 4. ***Mine Safety Disclosures***

Not applicable.

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PART II

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

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol PNG. As of February 22, 2012, the closing market price for our common units was $18.96 per unit and there were approximately 53,193,825 common units outstanding. As of December 31, 2010, there were approximately 10,200 record holders and beneficial owners (held in street name).

The following table sets forth high and low sales prices for our common units and the cash distributions declared per common unit for the periods indicated:

	Common Unit Price Range		Cash Distributions (1)
2011	**High**	**Low**	
4th Quarter	$ 18.99	$ 15.51	$ 0.3575
3rd Quarter	$ 23.72	$ 15.91	$ 0.3575
2nd Quarter	$ 24.92	$ 20.75	$ 0.3450
1st Quarter	$ 25.50	$ 22.73	$ 0.3450
2010			
4th Quarter	$ 25.75	$ 22.61	$ 0.3450
3rd Quarter	$ 26.65	$ 22.61	$ 0.3375
2nd Quarter (2)	$ 26.00	$ 22.25	$ 0.2114
1st Quarter (3)	$	$	$

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter. See Cash Distribution Policy below for a discussion of our policy regarding distribution payments.

(2) The distribution paid for the second quarter of 2010 represents our minimum quarterly distribution prorated for the period from May 5, 2010 (the date of closing of our initial public offering) through June 30, 2010.

(3) Our common units did not commence trading on the NYSE until April 2010.

Our common units are used as a form of compensation to our directors and our employees. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. Certain Relationships and Related Transactions, and Director Independence.

Cash Distribution Policy

We will distribute all of our available cash to our unitholders, of record on the applicable record date, within 45 days following the end of each quarter in the manner described below. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

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.

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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, incentive distributions in increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount as follows:

	Total Quarterly Distributions 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%

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.

The following table details the distributions subsequent to our initial public offering (in millions, except per unit amounts):

		Distributions Paid					
		Common	Series A Subordinated	General Partner			Distributions per limited partner
Date Declared	Date Paid or To Be Paid	Units	Units	Incentive	2%	Total	unit
January 12, 2012 [1]	February 14, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
October 11, 2011	November 14, 2011	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
July 11, 2011	August 12, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
April 11, 2011	May 13, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
January 12, 2011	February 14, 2011	$ 10.9	$ 4.1	$ 0.1	$ 0.3	$ 15.4	$ 0.3450
October 12, 2010	November 12, 2010	$ 10.7	$ 4.0	$	$ 0.3	$ 15.0	$ 0.3375
July 13, 2010	August 13, 2010 [2]	$ 6.7	$ 2.9	$	$ 0.2	$ 9.8	$ 0.2114

(1) Payable to unitholders of record on February 3, 2012, for the period October 1, 2011 through December 31, 2011.

(2) Amount represents a quarterly distribution of $0.3375 per unit prorated from the May 5, 2010 closing date of the IPO through June 30, 2010.

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 our partnership agreement, our credit facility or other debt agreements and applicable partnership law. Under the terms of the agreements governing our debt, we are prohibited from declaring or making any distribution to unitholders if a default or event of default (as defined in such agreements) exists. No such default has occurred. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters for information regarding securities authorized for issuance under equity compensation plans.

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Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of fiscal 2011, and we do not have any announced or existing plans to repurchase any of our common units.

Item 6. ***Selected Financial Data***

The historical financial information below was derived from our audited consolidated financial statements, or those of our predecessor as further discussed below, as of December 31, 2011, 2010, 2009, 2008 and 2007 and for the years ended December 31, 2011 and 2010, the period from September 3, 2009 through December 31, 2009, the period from January 1, 2009 through September 2, 2009 and the years ended December 31, 2008 and 2007. Pro forma information for the year ended December 31, 2009 is unaudited. As a result of the push-down accounting requirements applied in conjunction with the PAA Ownership Transaction (see Note 1 to our consolidated financial statements), the financial information of PNG for periods preceding (designated as Predecessor) and succeeding (designated as Successor) the PAA Ownership Transaction have been prepared under two different cost bases of accounting. A vertical line separates financial information for periods preceding and succeeding the PAA Ownership Transaction to highlight the fact that such information was prepared under different bases of accounting. The selected financial data should be read in conjunction with the Consolidated Financial Statements, including the notes thereto, and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

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	Predecessor			Successor	Pro Forma [1]	Successor	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	Year Ended December 31, 2009 (Unaudited)	Year Ended December 31, 2010	Year Ended December 31, 2011
	(in thousands, except for per unit, working storage capacity and monthly operating metrics)						
Statement of operations data:							
Total revenues	$ 36,945	$ 49,177	$ 46,929	$ 25,251	$ 72,180	$ 100,287	$ 342,964
Storage related costs and natural gas sales	3,847	8,934	8,792	7,003	15,795	23,465	205,092
Operating costs (except those shown below)	3,947	4,059	4,820	3,257	8,077	7,242	11,621
Fuel expense	1,140	2,320	1,816	578	2,394	2,368	4,924
General and administrative expenses	3,755	3,874	3,562	4,083	8,885	15,965	22,566
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Total costs and expenses	17,209	25,432	27,044	18,499	46,492	63,159	277,917
Operating income	19,736	23,745	19,885	6,752	25,688	37,128	65,047
Interest expense	(7,108)	(4,941)	(4,352)	(4,262)	(11,676)	(7,323)	(5,354)
Other income / (expense)	5,378	1,669	458	(2)	456	(18)	5
Income tax expense		(887)	(473)		(473)		
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Calculation of Limited Partner Interest in Net Income: [2]							
Net income	n/a	n/a	n/a	n/a	n/a	$ 24,359	$ 59,698
Less general partner interest in net income	n/a	n/a	n/a	n/a	n/a	537	1,793
Limited partner interest in net income	n/a	n/a	n/a	n/a	n/a	$ 23,822	$ 57,905
Per unit data:							
Basic net income per limited partner unit [2]	n/a	n/a	n/a	n/a	n/a	$ 0.54	$ 0.85
Diluted net income per limited partner unit [2]	n/a	n/a	n/a	n/a	n/a	$ 0.54	$ 0.85
Declared distribution per limited partner unit [3]	n/a	n/a	n/a	n/a	n/a	$ 0.89	$ 1.41
Balance sheet data (at end of period):							
Total assets	$ 674,765	$ 811,436		$ 900,407		$ 998,728	$ 1,849,999
Long-term debt [4]	$ 352,713	$ 415,263		$ 450,523		$ 259,900	$ 453,508
Total debt	$ 355,163	$ 417,713		$ 450,523		$ 259,900	$ 521,500
Members /partners capital	$ 294,717	$ 363,229		$ 432,744		$ 723,390	$ 1,285,626
Other financial data:							
Adjusted EBITDA [5][6]	$ 29,663	$ 31,001	$ 28,701	$ 12,165	$ 39,626	$ 53,857	$ 107,229
Distributable cash flow [5]	$ 22,156	$ 25,577	$ 23,965	$ 7,200	$ 26,863	$ 44,962	$ 99,914
Maintenance capital expenditures		$ 377	$ 384	$ 320	$ 704	$ 438	$ 798
Net cash provided by (used in) operating activities	$ 22,343	$ 21,818	$ 22,603	$ 15,265		$ 44,361	43,894
Net cash provided by (used in) investing activities	$ (177,280)	$ (118,890)	$ (58,561)	$ (9,656)		$ (103,580)	$ (810,274)
Net cash provided by (used in) financing activities	$ 145,743	$ 122,344	$ 23,636	$ (22,813)		$ 56,441	$ 766,530
Operating data:							
Net revenue margin [7]	$ 33,098	$ 40,243	$ 38,137	$ 18,248	$ 56,385	$ 76,452	$ 137,734
Other operating expenses / G&A / Other	(3,435)	(9,242)	(9,436)	(6,083)	(16,759)	(22,595)	(30,505)

Adjusted EBITDA	$ 29,663	$ 31,001	$ 28,701	$ 12,165	$ 39,626	$ 53,857	$ 107,229
Average working storage capacity (Bcf) [8]	26	27	36	40	38	47	71
Monthly Operating Metrics ($/Mcf)							
Net revenue margin	$ 0.11	$ 0.12	$ 0.13	$ 0.11	$ 0.12	$ 0.14	$ 0.16
Operating expenses / G&A / Other	(0.01)	(0.03)	(0.03)	(0.03)	(0.03)	(0.04)	(0.04)
Adjusted EBITDA	$ 0.10	$ 0.09	$ 0.10	$ 0.08	$ 0.09	$ 0.10	$ 0.12

(1) In September 2009, Plains All American Pipeline, L.P. became the sole owner of a predecessor of PNG by acquiring an additional 50% interest in that predecessor. Application of push-down accounting in conjunction with this transaction resulted in financial information for periods prior to and subsequent to this transaction being prepared under a different basis of accounting. For comparison purposes, the pro-forma presentation places the 2009 period on the same basis of accounting as the most recent period. The following items were impacted by the adjustment: General and administrative expenses, Depreciation, depletion, and amortization, and Interest expense. The net impact of the pro-forma adjustments was a $4.0 million decrease to Net income and Adjusted Net Income and a $1.2 million decrease in EBITDA and Adjusted EBITDA for the year ended December 31, 2009. These pro-forma adjustments are not attributable to the Partnership s May 2010 initial public offering. For further discussion, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

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(2) Reflective of general and limited partner interest in net income since closing of the Partnership s initial public offering. See Note 4 to our consolidated financial statements.

(3) Amount represents distributions per limited partner unit attributable to the fiscal period. Cash distributions for a fiscal quarter are declared and paid in the following calendar quarter. No distributions were declared for any periods prior to May 5, 2010, the closing of our initial public offering. Our series B subordinated units were not entitled to receive distributions for any of the periods presented. See Note 6 to our consolidated financial statements.

(4) Excludes approximately $68.0 million of borrowings under our $450 million five-year senior unsecured credit agreement as of December 31, 2011. Such borrowings, which are related to a portion of our funded hedged natural gas inventory, have been designated as working capital borrowings and must be repaid within one year. See Note 5 to our consolidated financial statements.

(5) For further discussion, please read, Non-GAAP and Segment Financial Measures.

(6) The period from September 3, 2009 through December 31, 2009 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.

(7) Net revenue margin equals total revenues less storage related costs, natural gas sales costs and mark-to-market of open derivative positions.

(8) Calculated as the sum of total owned working gas storage capacity at the end of each month divided by the number of months in the period.

Non-GAAP and Segment Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses Adjusted EBITDA and distributable cash flow in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. Adjusted EBITDA and/or distributable cash flow may exclude, for example, the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we have defined hereinafter as selected items impacting comparability. These additional financial measures are reconciled to net income, the most directly comparable measures as reported in accordance with GAAP, in the following table and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

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 applicable selected items impacting comparability.

Distributable cash flow, as determined by our general partner, 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 does not reflect actual cash on hand that is available for distribution to our unitholders.

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The following table reconciles Non-GAAP and segment financial measures to the most directly comparable measures as reported in accordance with GAAP (in thousands):

		Predecessor		Successor	Pro Forma (1)	Successor	Successor
	Year Ended December 31, 2007	Year Ended December 31, 2008	January 1 - September 2, 2009	September 3 - December 31, 2009	Year Ended December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2011
Adjusted EBITDA reconciliation							
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Income tax expense		887	473		473		
Interest expense, net of amounts capitalized	7,108	4,941	4,352	4,262	11,676	7,323	5,354
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Selected items impacting Adjusted EBITDA							
Equity compensation expense	553	(110)	304	1,467	1,771	2,747	4,046
Acquisition related costs						251	4,055
Insurance deductible related to property damage incident							500
Mark-to-market on open derivative positions	(524)	(548)		370	370	(370)	(138)
Adjusted EBITDA	**$ 29,663**	**$ 31,001**	**$ 28,701**	**$ 12,165**	**$ 39,626**	**$ 53,857**	**$ 107,229**
Distributable cash flow reconciliation							
Net income	$ 18,006	$ 19,586	$ 15,518	$ 2,488	$ 13,995	$ 29,787	$ 59,698
Depreciation, depletion and amortization	4,520	6,245	8,054	3,578	11,341	14,119	33,714
Income tax expense		887	473		473		
Acquisition related costs						251	4,055
Maintenance capital expenditures		(377)	(384)	(320)	(704)	(438)	(798)
Other non cash items:							
Equity compensation expense, net of cash payments	154	(216)	304	1,084	1,388	1,613	3,383
Mark-to-market on open derivative positions	(524)	(548)		370	370	(370)	(138)
Distributable cash flow	**$ 22,156**	**$ 25,577**	**$ 23,965**	**$ 7,200**	**$ 26,863**	**$ 44,962**	**$ 99,914**

(1) In September 2009, Plains All American Pipeline, L.P. became the sole owner of a predecessor of PNG by acquiring an additional 50% interest in that predecessor. Application of push-down accounting in conjunction with this transaction resulted in financial information for periods prior to and subsequent to this transaction being prepared under a different basis of accounting. For comparison purposes, the pro-forma presentation places the 2009 period on the same basis of accounting as the most recent period. The following items were impacted by the adjustment: General and administrative expenses, Depreciation, depletion and amortization, and Interest expense. The net impact of the pro-forma adjustments was a $4.0 million decrease to Net income and Adjusted Net Income and a $1.2 million decrease in EBITDA and Adjusted EBITDA for the year ended December 31, 2009. These pro-forma adjustments are not attributable to the Partnership s May 2010 initial public offering.

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations, including periods prior to our initial public offering on May 5, 2010. Such analysis should be read in conjunction with the historical audited consolidated financial statements, and accompanying notes. For ease of reference, we refer to the historical financial results of PAA Natural Gas Storage, LLC (PNGS) prior to our initial public offering as being our historical financial results. Unless the context otherwise requires, references to we, us, our, and the Partnership are intended to mean the business and operations of PAA Natural Gas Storage, L.P. (the Partnership or PNG) and its consolidated subsidiaries since May 5, 2010. When used in the historical context (i.e. prior to May 5, 2010), these terms are intended to mean the business and operations of PNGS. Unless the context indicates otherwise, for purposes of the following discussion PAA refers to Plains All American Pipeline, L.P. (the owner of our general partner) (NYSE: PAA) and its consolidated subsidiaries and affiliates other than the Partnership and its general partner and their respective subsidiaries.

For periods prior to our initial public offering, the historical consolidated financial statements are those of PNGS, our predecessor. Through the contribution of all of the equity interest of PNGS to us in connection with the closing of our initial public offering on May 5, 2010, all of the assets, liabilities and operations of PNGS were contributed directly or indirectly by PAA to the Partnership. For further discussion regarding the Partnership s initial public offering, please see Notes 1 and 6 to our consolidated financial statements.

As further discussed in Note 1 to our consolidated financial statements, PNGS became a wholly owned subsidiary of PAA on September 3, 2009 when PAA acquired an additional 50.0% interest in PNGS from Vulcan Capital (the PAA Ownership Transaction). Application of push-down accounting from PAA to PNGS resulted in a change in carrying value for certain assets and liabilities of PNGS.

Our discussion and analysis includes the following:

- Executive Summary
  - Company Overview
  - Overview of Operating Results, Capital Investments and Significant Activities
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company 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. In conjunction with our initial public offering in May 2010, PAA contributed the equity interest in the entities that owned its natural gas storage business to us. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities.

As of December 31, 2011, we owned and operated three natural gas storage facilities located in Louisiana, Mississippi and Michigan that have an aggregate working gas storage capacity of approximately 76 Bcf and an aggregate peak injection and withdrawal capacity of 4.1 Bcf per day and 6.4 Bcf per day, respectively. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Our Bluewater facility is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. As of December 31, 2011, through these facilities, PNG had a total of seven operational salt storage caverns and two depleted reservoirs used for natural gas storage. Additionally, our dedicated commercial marketing group captures short-term market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities.

Overview of Operating Results, Capital Investments and Significant Activities

Adjusted EBITDA for the year ended December 31, 2011 was $107.2 million, a 99% increase over Adjusted EBITDA of $53.9 million for the year ended December 31, 2010. This increase was primarily the result of the completion of the Southern Pines Acquisition on February 9, 2011, results of PNG Marketing, LLC (our commercial optimization company) and incremental revenues attributable to expansion of our Pine Prairie facility, including placing our fourth cavern into service during 2011, which provided an additional 10 Bcf of working gas capacity. See Results of Operations for further discussion and analysis of our operating results. Excluding acquisitions, expansion capital expenditures for 2011 were approximately $88.5 million. Such expenditures were principally associated with the ongoing development of our Pine Prairie and Southern Pines facilities.

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In February 2011, we completed the acquisition of SG Resources Mississippi, LLC (SG Resources) from SGR Holdings, L.L.C. for consideration of approximately $765 million (approximately $750 million, net of cash and other working capital acquired). The primary asset of SG Resources was the Southern Pines Energy Center (Southern Pines), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi.

In August 2011, we entered into a new $450 million five-year senior unsecured credit agreement, which replaced our $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

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 may 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 estimate will be recognized. Any subsequent adjustment to this estimate, if material, will be adjusted as if the amount was recognized when the combination occurred. 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 2011, 2010 or 2009.

Property 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 and equipment and most recently revised our estimates in September 2009. See Note 15 to our consolidated financial statements.

We also evaluate our property 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 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.

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We did not have impairments of property and equipment in 2011, 2010 or 2009.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, insurance claims, asset retirement obligations, property 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 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 Expense Recognitions. We recognize compensation expense for outstanding equity compensation awards granted under our Long Term Incentive Plan and similar plans sponsored by PAA. 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 applicable service period. For awards that contain a performance condition, the fair value of the award is recognized as compensation expense only if the attainment of the performance condition is considered probable. See Note 12 to our consolidated financial statements for further discussion of our equity compensation plans.

Valuation of Derivative Financial Instruments. We are required to measure derivatives at fair value pursuant to FASB guidance, the estimates of derivative gains or losses for a particular period are unrealized and will most likely not reflect the realized derivative gain or loss upon settlement of the derivative. We estimate the fair value of our derivatives with quoted prices, internal records and information received from third parties. For derivatives that are not exchange traded, the estimates we derive are based on indicative broker quotations that are further validated with market observable inputs. 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.

Results of Operations

PAA Ownership Transaction and Basis of Presentation

The tables below summarize our results of operations for the periods indicated. Due to the change in accounting basis that occurred as a result of the PAA Ownership Transaction, combining results of operations for 2009 periods prior to and subsequent to the PAA Ownership Transaction for purposes of comparison to 2010 results, without making appropriate adjustments, may not necessarily facilitate a meaningful analysis and would be inconsistent with relevant accounting and financial reporting authoritative guidance applicable to similar circumstances. As a result, we have elected to present pro forma results of operations for the year ended December 31, 2009 which have been prepared as if the PAA Ownership Transaction had occurred on January 1, 2009. Additionally, we have presented historical financial information for the periods from January 1, 2010 to September 2, 2010 and September 3, 2010 to December 31, 2010 for purposes of comparison to the comparable historical financial information for the periods prior to and subsequent to the PAA Ownership Transaction in 2009.

The pro forma information is based on assumptions that we believe are reasonable under the circumstances and are intended for illustrative purposes only. While not necessarily indicative of the results of the actual or future operations that would have been achieved had the PAA Ownership Transaction occurred on January 1, 2009, we believe this information provides a more meaningful basis of comparison for purposes of discussion of current period results as information is presented on a comparable accounting basis for complete fiscal periods. Pro forma adjustments reflected in the pro forma results for year ended December 31, 2009 impacted general and administrative expenses, interest expense and depreciation, depletion and amortization. Revenues and expense categories, other than those previously noted, were not materially impacted by the change in basis and amounts on a pro forma basis for the 2009 period are the summation of activity for the applicable 2009 historical periods prior to and subsequent from the PAA Ownership Transaction. Further discussion of the nature of the pro forma adjustments made is included as a part of this analysis. No pro forma adjustments were made attributable to the Partnership s May 2010 initial public offering.

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Year ended December 31, 2011 and year ended December 31, 2010

The following table includes our operating results for years ended December 31, 2011 and 2010 (amounts in thousands, except for average working storage capacity and monthly operating metrics):

	Year Ended December 31, 2011	Year Ended December 31, 2010	Favorable/(Unfavorable) Variance[1] 2011 - 2010 $	%
Revenues				
Firm storage services				
Reservation fees	$ 127,770	$ 85,651	$ 42,119	49%
Cycling fees and fuel-in-kind	8,411	5,314	3,097	58%
Hub services	9,806	6,190	3,616	58%
Natural gas sales	193,031		193,031	
Other	3,946	3,132	814	26%
Total revenue	342,964	100,287	242,677	242%
Storage related costs	(21,684)	(23,465)	1,781	8%
Natural gas sales costs	(183,408)		(183,408)	
Other operating costs (except those shown below)	(11,621)	(7,242)	(4,379)	(60)%
Fuel expense	(4,924)	(2,368)	(2,556)	(108)%
General and administrative expenses	(22,566)	(15,965)	(6,601)	(41)%
Other income / (expense)	5	(18)		
Equity compensation expense	4,046	2,747		
Acquisition related costs	4,055	251		
Insurance deductible related to property damage	500			
Mark-to-market of open derivative positions	(138)	(370)		
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Reconciliation to net income				
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Depreciation, depletion and amortization	(33,714)	(14,119)	(19,595)	(139)%
Interest expense, net of capitalized interest	(5,354)	(7,323)	1,969	27%
Income tax expense				
Equity compensation expense	(4,046)	(2,747)		
Acquisition related costs	(4,055)	(251)		
Insurance deductible related to property damage	(500)			
Mark-to-market of open derivative positions	138	370		
Net income	$ 59,698	$ 29,787	$ 29,911	100%
Operating Data:				
Net revenue margin [2]	$ 137,734	$ 76,452	$ 61,282	80%
Other operating expenses / G&A / Other	(30,505)	(22,595)	(7,910)	(35)%
Adjusted EBITDA	$ 107,229	$ 53,857	$ 53,372	99%
Average working storage capacity (Bcf)	71	47	24	51%
Monthly Operating Metrics ($/Mcf)				
Net revenue margin	$ 0.16	$ 0.14	$ 0.02	14%
Operating expenses / G&A / Other	(0.04)	(0.04)		

Adjusted EBITDA	$	0.12	$	0.10	$	0.02	20%

(1) Certain variance amounts and/or percentages were intentionally omitted.
(2) Net revenue margin equals total revenues less storage related costs, natural gas sales costs and mark-to-market of open derivative positions.

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Revenues and Related Costs. As noted in the table above, our total revenue and related costs increased during the year ended December 31, 2011 (the 2011 period) when compared to the year ended December 31, 2010 (the 2010 period). The primary reasons for such increase are the completion of the Southern Pines Acquisition on February 9, 2011, results of PNG Marketing, incremental revenues attributable to the expansion of our working gas capacity at the Pine Prairie facility by approximately 8 Bcf and 10 Bcf during 2011 and 2010, respectively, and additional leasing of capacity or third party transportation assets impacting the 2011 period relative to the 2010 period. These and other significant variances related to these periods are discussed in more detail below:

Firm storage reservation fees Firm storage reservation fee revenues increased in the 2011 period as compared to the 2010 period, primarily due to the completion of the Southern Pines Acquisition and incremental revenues attributable to the expansion of our working gas capacity at the Pine Prairie facility that reflect the benefit of a full year contribution from the 10 Bcf of working gas capacity placed in service during the second quarter of 2010 and a partial year contribution from the 8 Bcf of working gas capacity placed in service during the second quarter of 2011.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues increased in the 2011 period as compared to the 2010 period primarily due to the increase in working gas capacity in-service from 2010 to 2011 as a result of the completion of the Southern Pines Acquisition.

Hub services Hub services increased in the 2011 period as compared to the 2010 period. Our hub services activities are generally short-term in nature and their timing is influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply and demand. The increase in hub services revenues in the 2011 period as compared to the 2010 period is primarily due to the increase in working gas capacity in-service from 2010 to 2011 as a result of the Southern Pines Acquisition and our Pine Prairie expansion efforts along with additional usage of capacity leased from third party transportation assets.

Natural gas sales Natural gas sales of approximately $193.0 million during the 2011 period relate to revenues from sales of natural gas by PNG Marketing.

Other Other revenues increased in the 2011 period as compared to the 2010 period primarily due to the receipt of a fixed monthly access fee from Plains Gas Solutions, LLC (formerly known as CDM Max, LLC), an affiliate of PAA, relating to a natural gas services agreement entered into during 2011.

Storage related costs Storage related costs decreased in the 2011 period as compared to the 2010 period. The decrease was primarily the result of a decrease in the amount of leased storage and a reduction in costs incurred to manage our storage capacity. This decrease was partially offset by an increase in leased transportation assets in the 2011 period as compared to the 2010 period.

Natural gas sales costs Natural gas sales costs of approximately $183.4 million during the 2011 period reflect the cost of natural gas sold by PNG Marketing.

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

Operating costs Field operating costs increased in the 2011 period as compared to the 2010 period. The increase is primarily related to the increase in working gas capacity in-service from 2010 to 2011 as a result of our expansion efforts at our Pine Prairie facility and the completion of the Southern Pines Acquisition. The 2011 period includes approximately $0.5 million of expense for the property insurance deductible related to the January 2011 operational incident and fire at our Bluewater facility.

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Fuel expense Fuel expense increased in the 2011 period as compared to the 2010 period primarily due to the increase in in-service working gas capacity in 2011 as compared to 2010 as a result of the Southern Pines Acquisition and expansion efforts at our Pine Prairie facility.

General and administrative expenses General and administrative expenses increased in the 2011 period as compared to the 2010 period. The increase primarily resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the operation of our commercial optimization group for a full year in 2011, along with additional administrative costs associated with being a public company for a full year in 2011. Additionally, during the 2011 period we recognized approximately $2.7 million of equity compensation expense associated with awards granted by PAA compared to approximately $1.5 million in the 2010 period. Although we will not bear the economic burden of these awards, we benefit from the services underlying these awards. The 2011 period also includes approximately $4.1 million of acquisition and integration costs incurred in conjunction with the Southern Pines Acquisition. The 2010 period includes non-recurring costs of approximately $2.4 million associated with acquisition evaluation expenses, the start-up of our commercial optimization group and general and administrative expenses associated with our initial public offering efforts.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2011 period as compared to the 2010 period. The increase resulted primarily from an increased amount of depreciable assets resulting from the Southern Pines acquisition and our internal growth projects, including the additional 10 Bcf and 11 Bcf of storage capacity placed into service at our Pine Prairie facility in April 2011 and April 2010, respectively. Additionally, amortization of intangible assets acquired in conjunction with the Southern Pines Acquisition was approximately $14.7 million during the 2011 period.

Interest expense, net of capitalized interest Interest expense, net of capitalized interest, decreased in the 2011 period when compared to the 2010 period. Interest expense, on a gross basis, increased to approximately $16.3 million in the 2011 period as compared to approximately $14.9 million in the 2010 period. The increase principally resulted from an increase in average outstanding debt balances in the 2011 period as compared to the 2010 period and was partially offset by a decrease in average interest rates in the 2011 period as compared to 2010 period. Capitalized interest was approximately $10.9 million and $7.6 million in the 2011 and 2010 periods, respectively. Capitalized interest increased primarily due to an increase in assets not yet in service as a result of the Southern Pines Acquisition.

Year ended December 31, 2010 and pro forma year ended December 31, 2009

The following table includes our operating results for the year ended December 31, 2010, the period from January 1, 2009 through September 2, 2009 and the period from September 3, 2009 to December 31, 2009 on a historical basis and for the year ended December 31, 2009 on a pro forma basis (amounts in thousands, except for average working storage capacity and monthly operating metrics). Information designated as Predecessor and Successor 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 following table to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting.

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	Successor Year Ended December 31, 2010	Pro Forma Year Ended December 31, 2009	Successor September 3, 2009 through December 31, 2009	Predecessor January 1, 2009 through September 2, 2009	Favorable/(Unfavorable) Variance[1] 2010 - 2009 Pro forma $	%
Revenues						
Firm storage services						
Reservation fees	$ 85,651	$ 62,535	$ 22,919	$ 39,616	$ 23,116	37%
Cycling fees and fuel-in-kind	5,314	4,086	1,053	3,033	1,228	30%
Hub services	6,190	4,625	1,637	2,988	1,565	34%
Other	3,132	934	(358)	1,292	2,198	235%
Total revenue	100,287	72,180	25,251	46,929	28,107	39%
Storage related costs	(23,465)	(15,795)	(7,003)	(8,792)	(7,670)	(49)%
Other operating costs (except those shown below)	(7,242)	(8,077)	(3,257)	(4,820)	835	10%
Fuel expense	(2,368)	(2,394)	(578)	(1,816)	26	1%
General and administrative expenses	(15,965)	(8,885)	(4,083)	(3,562)	(7,080)	(80)%
Other income / (expense)	(18)	456	(2)	458	(474)	(104)%
Equity compensation expense	2,747	1,771	1,467	304		
Acquisition related costs	251					
Mark-to-market of open derivative positions	(370)	370	370			
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Reconciliation to net income						
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Depreciation, depletion and amortization	(14,119)	(11,341)	(3,578)	(8,054)	(2,778)	(24)%
Interest expense, net of capitalized interest	(7,323)	(11,676)	(4,262)	(4,352)	4,353	37%
Income tax expense		(473)		(473)		
Equity compensation expense	(2,747)	(1,771)	(1,467)	(304)		
Acquisition related costs	(251)					
Mark-to-market of open derivative positions	370	(370)	(370)			
Net income	$ 29,787	$ 13,995	$ 2,488	$ 15,518	$ 15,792	113%
Operating Data:						
Net revenue margin [2]	$ 76,452	$ 56,755	$ 18,618	$ 38,137	$ 19,697	35%
Other operating expenses / G&A / Other	(22,595)	(17,129)	(6,453)	(9,436)	(5,466)	(32)%
Adjusted EBITDA	$ 53,857	$ 39,626	$ 12,165	$ 28,701	$ 14,231	36%
Average working storage capacity (Bcf)	47	38	40	36	9	24%
Monthly Operating Metrics ($/Mcf)						
Net revenue margin	$ 0.14	$ 0.12	$ 0.12	$ 0.13	$ 0.02	17%
Operating expenses / G&A / Other	(0.04)	(0.03)	(0.03)	(0.03)	(0.01)	(33)%
Adjusted EBITDA	$ 0.10	$ 0.09	$ 0.09	$ 0.10	$ 0.01	11%

(1) Certain variance amounts and/or percentages were intentionally omitted.

(2) Net revenue margin equals total revenues less storage related costs and mark-to-market of open derivative positions.

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Pro Forma Adjustments

Pro forma adjustments reflected in the information above include:

- An increase in general and administrative expenses of approximately $1.2 million for the pro forma year ended December 31, 2009, to reflect an increase in personnel costs allocated to us from PAA as a result of an increase in services provided on our behalf.

- A net increase in interest expense, net of capitalized interest of approximately $3.1 million for the pro forma year ended December 31, 2009. In conjunction with the PAA Ownership Transaction amounts outstanding under our credit facilities were extinguished and replaced with a related party note payable to PAA which accrued interest at a rate of 6.5%, which was higher than historical rates of interest on our predecessor s extinguished credit facilities. The increase in interest rate results in incremental interest expense in the 2009 period on a pro forma basis. This increase was partially offset by an increase in capitalized interest.

- A net decrease in depreciation, depletion and amortization expense of approximately $0.3 million for the pro forma year ended December 31, 2009. Depreciation expense increased by $0.6 million in the pro forma year ended December 31, 2009 due to fair value adjustments recorded in conjunction with the PAA Ownership Transaction, partially offset by a revision in estimates of useful lives. Amortization expense decreased by $0.9 million in the pro forma year ended December 31, 2009 due to changes in the composition of our intangible assets, including debt issuance costs, and their associated estimated useful lives.

Revenues and Related Costs. As noted in the table above, our total revenue increased during the year ended December 31, 2010 (the 2010 period) when compared to the year ended December 31, 2009 on a pro forma basis (the 2009 pro forma period). The primary reason for such increase is the placement into service of an additional 8 Bcf and 10 Bcf of working gas storage capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively. Additionally, total revenues and storage related costs increased due to additional leasing of third party storage and transportation capacity in 2010. These and other significant variances related to these periods are discussed in more detail below:

- *Firm storage reservation fees* Firm storage reservation fee revenues increased for the 2010 period as compared to the 2009 pro forma period, primarily due to the placement into service of an additional 8 Bcf and 10 Bcf of working gas capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively, which resulted in approximately $20 million in incremental revenues generated by our Pine Prairie facility during the 2010 period. Revenues from firm storage reservation fees were also positively impacted by loan activities and additional revenue generating activities associated with increased amounts of leased storage and transportation capacity. See Storage related costs below.

- *Firm storage cycling fees and fuel-in-kind* Firm storage cycling fees and fuel-in-kind revenues increased in the 2010 period as compared to the 2009 pro forma period. The increase was primarily driven by an increase in the period-over-period average natural gas price of approximately 10% in the 2010 period as compared to the 2009 pro forma period, which increased our fuel-in-kind revenues. Such increase was partially offset by a reduction in cycling volumes.

- *Hub services* Hub services increased in the 2010 period as compared to the 2009 pro forma period. This increase primarily related to increased wheeling and balancing services as a result of utilizing leased transportation capacity during the 2010 period to augment the service capabilities of our owned assets. See Storage related costs below. Our hub services activities are generally short-term in nature and their timing and extent of activity are influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply, demand and working gas capacity.

- *Other* Other revenue for each of the periods consists primarily of crude oil sales and activities associated with natural gas storage-related futures derivative positions. Crude oil sales increased in the 2010 period as compared to the 2009 pro forma period by approximately $1.6 million. The increase reflected higher average realized prices in 2010 versus the prior year period, combined with an increase in production in 2010. The 2010 increase in production was primarily due to our completion of a new well drilled as part of our ongoing liquids removal efforts at our Bluewater facility. The 2010 period and the 2009 pro forma period each include losses of approximately $0.4 million associated with a natural gas storage-related futures derivative position which was closed out during the second quarter of 2010 at a realized loss of approximately $0.8 million. The 2010 period also reflects a gain of approximately $0.6 million associated with sales of excess fuel inventory and natural gas acquired for operational purposes in the fourth quarter of 2010.

Storage related costs Storage related costs increased in the 2010 period as compared to the 2009 pro forma period due to an increase in the amount of storage and transportation capacity leased from third parties. In addition, we experienced higher costs as a result of increased loan transactions in 2010 as compared to 2009. Further, during the 2010 period we released a portion of our leased transportation capacity to third parties through August 2011. The 2010 period reflects a loss of approximately $0.4 million representing the portion of the reservation charges that we do not anticipate recovering over the remaining period of the capacity release. See Firm storage reservation fees above.

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

Operating costs Field operating costs decreased in the 2010 period as compared to the 2009 pro forma period. The decrease is primarily related to a decrease in property tax expense attributable to revisions of estimated property tax obligations.

Fuel expense Fuel expense did not change significantly in the 2010 period as compared to the 2009 pro forma period.

General and administrative expenses General and administrative expenses increased in the 2010 period as compared to the 2009 pro forma period. The approximately $7.1 million increase resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the establishment of our commercial optimization group, along with additional administrative costs associated with being a public company. Increased costs in 2010 reflect approximately $2.4 million associated with acquisition evaluation expenses, the start-up of our commercial optimization group and internal general and administrative expenses associated with our initial public offering efforts. Additionally, the 2010 period includes approximately $1.5 million of equity compensation expense associated with awards granted by PAA to certain officers of PAA that will be settled in PNG common units owned by PAA upon vesting. Although the entire economic burden of these agreements will be borne solely by PAA, since these individuals also serve as officers of PNG and PNG benefits as a result of the services they provide, we are required to reflect the compensation expense associated with these awards in our financial statements.

Other income / (expense) Other income / (expense) for the 2009 pro forma period was comprised primarily of interest income and ineffectiveness associated with an interest rate swap agreement. The reduction of other income / (expense) for the 2010 period was driven by the termination of the swap agreement in conjunction with the PAA Ownership Transaction and, following the PAA Ownership Transaction, a significant reduction in the amount of cash balances carried by us, which resulted in a decrease in interest income.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the 2010 period as compared to the 2009 pro forma period. Depreciation increased by approximately $2.8 million, primarily as a result of an increased amount of depreciable assets resulting from our internal growth projects including the additional 8 Bcf and 10 Bcf of storage capacity placed into service in April 2009 and April 2010, respectively. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $2.3 million and $2.6 million in the 2010 period and 2009 pro forma period, respectively.

Interest expense, net of capitalized interest Interest expense decreased in the 2010 period when compared to the 2009 pro forma period. The decrease principally resulted from decreases in both average debt balances outstanding and average interest rates in the 2010 period as compared to the 2009 pro forma period. Capitalized interest was approximately $7.6 million and $15.6 million in the 2010 period and the 2009 pro forma period, respectively, with decreases in both average debt balances outstanding and average interest rates as well as an increase in in-service capacity at our Pine Prairie facility period over period.

Income tax expense As a partnership we are not subject to U.S. federal income taxes, rather, the tax effect of our operations is passed through to our partners and unitholders. Our income tax expense consists principally of state income taxes calculated on an apportionment basis. The income tax expense is lower in the 2010 period when compared to the 2009 pro forma period due to the combined impact of the expansion in our areas of operations outside of the applicable state, and ownership changes that resulted in our inclusion as a consolidated subsidiary of PAA.

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Periods from January 1 to September 2, 2010 and 2009 and from September 3 to December 31, 2010 and 2009

The following table includes our operating results for the historical periods from January 1 to September 2, 2010 and 2009 and from September 3 to December 31, 2010 and 2009 (amounts in thousands, except for average working storage capacity and monthly operating metrics). Historical information for the periods from January 1 to September 2, 2010 and September 3 to December 31, 2010 is unaudited. Information designated as Predecessor and Successor 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 following table to highlight the fact that the financial information for such periods has been prepared under a different basis of accounting.

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		Successor		Predecessor	Favorable/(Unfavorable) Variance [1]			
	September 3, 2010 through December 31, 2010	January 1, 2010 through September 2, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009	September through December 2010 to 2009 $	%	January through September 2010 to 2009 $	%
Revenues								
Firm storage services								
Reservation fees	$ 30,994	$ 54,657	$ 22,919	$ 39,616	$ 8,075	35%	$ 15,041	38%
Cycling fees and fuel-in-kind	1,874	3,440	1,053	3,033	821	78%	407	13%
Hub services	2,792	3,398	1,637	2,988	1,155	71%	410	14%
Other	1,616	1,516	(358)	1,292	1,974	551%	224	17%
Total revenue	37,276	63,011	25,251	46,929	12,025	48%	16,082	34%
Storage related costs	(8,878)	(14,587)	(7,003)	(8,792)	(1,875)	(27)%	(5,795)	(66)%
Other operating costs (except those shown below)	(2,719)	(4,523)	(3,257)	(4,820)	538	17%	297	6%
Fuel expense	(961)	(1,407)	(578)	(1,816)	(383)	(66)%	409	23%
General and administrative expenses	(6,207)	(9,758)	(4,083)	(3,562)	(2,124)	(52)%	(6,196)	(174)%
Other income/(expense)	(7)	(11)	(2)	458	(5)	(250)%	(469)	(102)%
Equity compensation expense	1,937	810	1,467	304	470		506	
Acquisition related costs	251				251			
Mark-to-market of open derivative positions		(370)	370		(370)			
Adjusted EBITDA	$ 20,692	$ 33,165	$ 12,165	$ 28,701	$ 8,527	70%	$ 4,464	16%
Reconciliation to net income								
Adjusted EBITDA	$ 20,692	$ 33,165	$ 12,165	$ 28,701	$ 8,527	70%	$ 4,464	16%
Depreciation, depletion and amortization	(5,065)	(9,054)	(3,578)	(8,054)	(1,487)	(42)%	(1,000)	(12)%
Interest expense, net of capitalized interest	(1,028)	(6,295)	(4,262)	(4,352)	3,234	76%	(1,943)	(45)%
Income tax expense				(473)			473	100%
Equity compensation expense	(1,937)	(810)	(1,467)	(304)	(470)		(506)	
Acquisition related costs	(251)				(251)			
Mark-to-market of open derivative positions		370	(370)		370		370	
Net income	$ 12,411	$ 17,376	$ 2,488	$ 15,518	$ 9,923	399%	$ 1,858	12%
Operating Data:								
Net revenue margin [2]	$ 28,398	$ 48,054	$ 18,618	$ 38,137	$ 9,780	53%	$ 9,917	26%
Other operating expenses / G&A / Other	(7,706)	(14,889)	(6,453)	(9,436)	(1,253)	(19)%	(5,453)	(58)%
Adjusted EBITDA	$ 20,692	$ 33,165	$ 12,165	$ 28,701	$ 8,527	70%	$ 4,464	16%
Average working storage capacity (Bcf)	50	46	40	36	10	25%	10	28%
Monthly Operating Metrics ($/Mcf)								
Net revenue margin	$ 0.14	$ 0.13	$ 0.12	$ 0.13	$ 0.02	17%	$	
Operating expenses / G&A / Other	(0.04)	(0.04)	(0.03)	(0.03)	(0.01)	(33)%	(0.01)	(33)%
Adjusted EBITDA	$ 0.10	$ 0.09	$ 0.09	$ 0.10	$ 0.01	11%	$ (0.01)	(10)%

(1) Certain variance amounts and/or percentages were intentionally omitted.

(2) Net revenue margin equals total revenues less storage related costs and mark-to-market of open derivative positions.

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Periods from January 1, 2010 to September 2, 2010 and January 1, 2009 to September 2, 2009

Revenues and Related Costs. As noted in the table above, our total revenue increased during the period from January 1, 2010 to September 2, 2010 (the January to September 2010 period) when compared to the period from January 1, 2009 to September 2, 2009 (the January to September 2009 period). The primary reason for such increase is the placement into service of an additional 8 Bcf and 10 Bcf of working gas storage capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively. Additionally, total revenues and storage related costs increased due to additional leasing of third party storage and transportation assets in 2010. These and other significant variances related to these periods are discussed in more detail below:

Firm storage reservation fees Firm storage reservation fee revenues increased for the January to September 2010 period as compared to the January to September 2009 period, primarily due to the placement into service of an additional 8 Bcf and 10 Bcf of working gas capacity at our Pine Prairie facility during the second quarters of 2009 and 2010, respectively, which resulted in approximately $12 million in incremental revenues generated by our Pine Prairie facility during the 2010 period. Revenues from firm storage reservation fees were also positively impacted by loan activities and additional revenue generating activities associated with increased amounts of leased storage and transportation capacity. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues increased in the January to September 2010 period as compared to the January to September 2009 period. The increase was primarily driven by an increase in the period-over-period average natural gas price of approximately 21% in the 2010 as compared to 2009, which increased our fuel-in-kind revenues. Such increase was partially offset by a slight reduction in cycling volumes.

Hub services Hub services increased in the January to September 2010 period as compared to the January to September 2009 period. This increase primarily related to increased wheeling and balancing services as a result of utilizing leased transportation capacity during 2010 to augment the service capabilities of our owned assets. See Storage related costs below. Our hub services activities are generally short-term in nature and their timing and extent of activity are influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply, demand and working gas capacity.

Other Other revenue for each of the periods consists primarily of crude oil sales and activities associated with natural gas storage-related futures derivative positions. Crude oil sales increased in the January to September 2010 period as compared to the January to September 2009 period by approximately $0.6 million. The increase reflected higher average realized prices in 2010 as compared to 2009 combined with an increase in production in 2010. The 2010 increase in production was primarily due to our completion of a new well drilled as part of our ongoing liquids removal efforts at our Bluewater facility. The January to September 2010 period includes a loss of approximately $0.4 million associated with a natural gas storage related futures derivative position which was closed out during the second quarter of 2010 at a realized loss of approximately $0.8 million.

Storage related costs Storage related costs increased in the January to September 2010 period as compared to the January to September 2009 period due to an increase in the amount of storage and transportation capacity leased from third parties. In addition, we experienced higher costs as a result of increased loan transactions in January to September 2010 period as compared to the January to September 2009 period. See Firm storage reservation fees above.

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

Operating costs Field operating costs decreased in the January to September 2010 period as compared to the January to September 2009 period. The decrease is primarily related to a decrease in property tax expense attributable to revisions of estimated property tax obligations.

Fuel expense Fuel expense decreased in the January to September 2010 period as compared to the January to September 2009 period due to lower fuel volumes used.

General and administrative expenses General and administrative expenses increased in the January to September 2010 period as compared to the January to September 2009 period. The increase resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the establishment of our commercial optimization group, along with additional administrative costs associated with being a public company. General and

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administrative expense for the 2010 period reflects approximately $2.4 million associated with acquisition evaluation expenses, the start-up of our commercial optimization group and internal general and administrative expenses associated with our initial public offering efforts. The January to September 2010 period also reflects an increase of approximately $1.2 million of additional personnel costs allocated to us from PAA as a result of an increase in services provided on our behalf compared to the January to September 2009 period.

Other income / (expense) Other income / (expense) for the January to September 2009 period was comprised primarily of interest income and ineffectiveness associated with an interest rate swap agreement. The reduction of other income / (expense) for the January to September 2010 period when compared to the January to September 2009 period was driven by the termination of the swap agreement in conjunction with the PAA Ownership Transaction and, following the PAA Ownership Transaction, a significant reduction in the amount of cash balances carried by us, which resulted in a decrease in interest income.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the January to September 2010 period as compared to the January to September 2009 period. Depreciation and depletion increased by approximately $1.7 million, primarily as a result of an increased amount of depreciable assets resulting from our internal growth projects including the additional 8 Bcf and 10 Bcf of storage capacity placed into service in April 2009 and April 2010, respectively. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $1.4 million and $2.0 million in the January to September 2010 period and the January to September 2009 period, respectively.

Interest expense, net of capitalized interest Interest expense, net of capitalized interest increased in the January to September 2010 period when compared to the January to September 2009 period. Interest expense, on a gross basis, decreased principally due to decreases in both average debt balances outstanding and average interest rates in the January to September 2010 period as compared to the January to September 2009 period. Capitalized interest was approximately $6.2 million and $10.2 million in the January to September 2010 period and the January to September 2009 period, respectively, with decreases in both average debt balances outstanding and average interest rates as well as an increase in in-service capacity at our Pine Prairie facility period over period.

Income tax expense As a partnership we are not subject to U.S. federal income taxes, rather, the tax effect of our operations is passed through to our partners and now our unitholders. Our income tax expense consists principally of state income taxes calculated on an apportionment basis. Income tax expense is lower in the January to September 2010 period when compared to the January to September 2009 period due to the combined impact of the expansion in our areas of operations outside of the applicable state, and ownership changes that resulted in our inclusion as a consolidated subsidiary of PAA.

Periods from September 3, 2010 to December 31, 2010 and September 3, 2009 to December 31, 2009

Revenues and Related Costs. As noted in the table above, our total revenue increased during the period from September 3, 2010 to December 31, 2010 (the September to December 2010 period) when compared to the period from September 3, 2009 to December 31, 2009 (the September to December 2009 period). The primary reason for such increase is the placement into service of an additional 10 Bcf of working gas storage capacity at our Pine Prairie facility during the second quarter of 2010. Additionally, total revenues and storage related costs increased due to additional leasing of third party storage and transportation assets in 2010. These and other significant variances related to these periods are discussed in more detail below:

Firm storage reservation fees Firm storage reservation fee revenues increased for the September to December 2010 period as compared to the September to December 2009 period, primarily due to the placement into service of an additional 10 Bcf of working gas capacity at our Pine Prairie facility during the second quarter of 2010 which resulted in approximately $8.2 million in incremental revenues generated by our Pine Prairie facility during the 2010 period. Revenues from firm storage reservation fees were also positively impacted by loan activities and additional revenue generating activities associated with increased amounts of leased storage and transportation capacity. See Storage related costs below.

Firm storage cycling fees and fuel-in-kind Firm storage cycling fees and fuel-in-kind revenues increased in the September to December 2010 period as compared to the September to December 2009 period. The increase was primarily driven by an increase in injection activity associated with the increase in in-service working gas capacity period over period along partially offset by a decrease in period-over-period average natural gas price of approximately 12% in the 2010 period as compared to the 2009 period which increased our fuel-in-kind and cycling fee revenues.

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Hub services Hub services increased in the September to December 2010 period as compared to the September to December 2009 period. This increase primarily related to increased wheeling and balancing services as a result of utilizing leased transportation capacity during the 2010 to augment the service capabilities of our owned assets. See Storage related costs below. Our hub services activities are generally short-term in nature and their timing and extent of activity are influenced by weather, operating disruptions, import activities and other conditions that result in temporary disruptions in supply, demand and working gas capacity.

Other Other revenue for each of the periods consists primarily of crude oil sales and activities associated with natural gas storage-related futures derivative positions. Crude oil sales increased in the September to December 2010 period as compared to the September to December 2009 period by approximately $1.0 million. The increase is due to an increase in production as a result of our completion of a new well drilled as part of our ongoing liquids removal efforts at our Bluewater facility. Prior to the completion of this well our ability to produce oil was generally limited to the first and second quarters of each year. The September to December 2009 period each include a loss of approximately $0.4 million associated with a natural gas storage-related futures derivative position which was closed out during the second quarter of 2010 at a realized loss of approximately $0.8 million. The September to December 2010 period also reflects a gain of approximately $0.6 million associated with sales of excess fuel inventory and natural gas acquired for operational purposes in the fourth quarter of 2010.

Storage related costs Storage related costs increased in the September to December 2010 period as compared to the September to December 2009 due to an increase in the amount of storage and transportation capacity leased from third parties. In addition, we experienced higher costs as a result of increased loan transactions in September to December 2010 as compared to the September to December 2009 period. Further, during the 2010 period we released a portion of our leased transportation capacity to third parties through August 2011. The 2010 period reflects a loss of approximately $0.4 million representing the portion of the reservation charges that we did not anticipate recovering over the remaining period of the capacity release. See Firm storage reservation fees above.

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

Operating costs Field operating costs decreased in the September to December 2010 period as compared to the September to December 2009 period. The decrease is primarily related to a decrease in property tax expense attributable to revisions of estimated property tax obligations.

Fuel expense Fuel expense increased in the September to December 2010 period as compared to the September to December 2009 period. An increase in fuel volumes used was partially offset by lower average fuel prices.

General and administrative expenses General and administrative expenses increased in the September to December 2010 period as compared to the September to December 2009 period. The increase resulted from the continued expansion of our business and growth in personnel costs, including equity compensation expense and the establishment of our commercial optimization group, along with additional administrative costs associated with being a public company. Additionally, during the September to December 2010 period we recognized approximately $1.5 million of equity compensation expense associated with awards granted by PAA to certain officers of PAA which will be settled in PNG common units owned by PAA upon vesting. Although the entire economic burden of these agreements will be borne solely by PAA, since these individuals also serve as officers of PNG and PNG benefits as a result of the services they provide, we are required to reflect the compensation expense associated with these awards in our financial statements.

Depreciation, depletion and amortization Depreciation, depletion and amortization expense increased in the September to December 2010 period as compared to the September to December 2009 period. Depreciation and depletion increased by approximately $1.2 million, primarily as a result of an increased amount of depreciable assets resulting from our internal growth projects including the additional 8 Bcf and 10 Bcf of storage capacity placed into service in April 2009 and April 2010, respectively. Depreciation, depletion and amortization expense includes amortization of debt issue costs and intangibles of $0.9 million and $0.6 million in the September to December 2010 period and the September to December 2009 period, respectively.

Interest expense, net of capitalized interest Interest expense decreased in the September to December 2010 period when compared to the September to December 2009 period. The decrease principally resulted from decreases in both average debt balances outstanding and average interest rates in the September to December 2010 period as compared to the September to December 2009 period. Capitalized interest was approximately $1.4 million and $5.4 million in the September to December 2010 period and the September to December 2009 period, respectively, with decreases in both average debt balances outstanding and average interest rates as well as an increase in in-service capacity at our Pine Prairie facility period over period.

Outlook

Following a multi-year period of favorable market conditions for natural gas storage providers, overall market conditions for both hub services and firm storage services began to deteriorate in 2010 and remained soft throughout 2011. Factors we believe contributed to this deterioration include reduced spread and basis differentials and associated volatility, which we believe were impacted by a combination of factors, including weather patterns, shale gas production and pipeline infrastructure additions. Market conditions remained challenging throughout 2011 with seasonal spreads, as reflected by the October 2011 to January 2012 NYMEX spread, ranging from $0.37-$0.82.

We believe certain of the supply and demand factors contributing to the weakness are self-correcting over time and that the long-term demand for storage is positive. Additionally, we believe our asset base, contract profile, financial position and low risk, economically attractive expansion projects will enable us to maintain our cash flows for the next several years even if such conditions persist. We also believe we are reasonably well positioned to pursue and consummate additional acquisitions.

However, if weak gas storage market conditions persist or worsen, in addition to adversely affecting hub services activities, they may adversely impact the lease rates our customers are willing to pay for firm storage services with respect to new capacity under construction as well as renewals of existing capacity upon expirations of existing term leases. Accordingly, although a significant portion of our existing capacity is underpinned by multi-year firm storage contracts, we can provide no assurance that our operating and financial results will not be adversely impacted by adverse overall market conditions. In addition, we can provide no assurances that our acquisition and organic growth efforts will be successful.

Liquidity and Capital Resources

Overview

Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to storage costs incurred, natural gas purchases and other operating and general and administrative expenses, interest payments on our outstanding debt and distributions to our owners, (ii) maintenance and expansion capital expenditures, including purchases of base gas, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our long-term debt. We generally expect to fund our short-term cash requirements through our primary sources of liquidity, which consist of our cash flow generated from operations as well as borrowings under our credit agreement. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or proceeds from the issuance of additional equity or debt securities.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). Although the Dodd-Frank Act includes provisions regarding the use of financial instruments, and the scope and applicability of these provisions as implemented may continue to develop, our current assessment is that the direct effects of the Dodd-Frank Act on PNG will be limited to additional documentation and record-keeping requirements We cannot, however, predict the effect the Dodd-Frank Act may have on the futures and capital markets, which may affect the depth and quality of our counterparties and lenders and, as a result, our liquidity and access to capital.

Credit Agreement

In August 2011, we entered into a new $450 million five-year senior unsecured credit agreement, which provides for (i) $250 million under a revolving credit facility, which may be increased at our option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the GO Zone Term Loans) pursuant to the purchase, at par, of the GO Bonds we acquired in conjunction with the Southern Pines Acquisition. The revolving credit facility expires in August 2016. The purchasers of the two GO Zone Term Loans have the right to put, at par, to PNG the GO Zone Term Loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. This new credit agreement replaced our $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

Our new credit agreement contains covenants and events of default which are substantially consistent with those contained in our previous credit facility. Our new credit agreement restricts, among other things, our ability to 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. In addition, the credit agreement contains restrictive covenants, including those that restrict our ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of our assets or enter

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into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, require us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also require that we maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement.

At December 31, 2011, borrowings of approximately $321.5 million were outstanding under our new credit agreement, which includes approximately $121.5 million under the revolving credit facility. Additionally, we had approximately $3.0 million of outstanding letters of credit under our revolving credit facility. As of December 31, 2011, we were in compliance with the covenants, including the financial ratios, contained in our new credit agreement. Based on the most restrictive covenant, at December 31, 2011 our incremental borrowing ability under our credit agreement was limited to approximately $125.5 million. Notably, the restriction on debt incurrence does not limit our ability to incur hedged inventory debt. Also, the formula for determining EBITDA in the context of the financial ratios allows for inclusion of pro forma EBITDA arising from certain capital investments, including for acquisitions and certain capital expenditures related to our Pine Prairie and Southern Pines expansions. We believe our credit facility and available debt capacity is adequate to fund our current capital program.

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. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guaranties or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us. In connection with the purchase of natural gas by our dedicated commercial marketing group, approximately $31 million of parental guarantees issued by PAA on behalf of PNG Marketing were outstanding as of December 31, 2011 (see Note 11 to our consolidated financial statements for further discussion).

Sources of Liquidity

Our current sources of liquidity include:

- cash generated from operations;
- borrowings under our credit agreement;
- 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.

We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (Traditional Shelf). We have not issued any securities under the Traditional Shelf.

To maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for future expansion projects with equity and cash flow in excess of distributions.

For a discussion of the impact that the price of natural gas might have on our operations and liquidity and capital resources, see Item 7A. 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, natural gas inventory balances and short-term debt. 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. As of December 31, 2011 we had a working capital deficit of approximately $16.2 million.

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Historical Cash Flow Information

The following table reflects cash flows for the applicable periods (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009
Net cash provided by (used in):				
Operating activities	$ 43,894	$ 44,361	$ 15,265	$ 22,603
Investing activities	(810,274)	(103,580)	(9,656)	(58,561)
Financing activities	766,530	56,441	(22,813)	23,636
Net increase/(decrease) in cash	$ 150	$ (2,778)	$ (17,204)	$ (12,322)
Adjusted EBITDA	$ 107,229	$ 53,857	$ 12,165	$ 28,701

Operating Activities. The primary drivers of cash flow from our operations are (i) the collection of amounts related to the storage and sales of natural gas, and (ii) the payment of amounts related to purchases of natural gas and expenses, principally storage and transportation related costs, field operating costs and general and administrative expenses. Cash provided by operating activities is significantly impacted in periods where we are increasing or decreasing the amount of inventory in storage. In the month that we pay for stored natural gas, we borrow under our credit facility to pay for the natural gas, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored natural gas. During 2011 our cash generated from our recurring operations increased over 2010, however, we increased the amount of inventory that was funded under our credit facility resulting in a negative impact to our cash flow from operations.

Investing Activities. Our investing activities for each of the periods listed above primarily relate to the continued expansion of our Pine Prairie and Southern Pines facilities and the acquisition of the related base gas required to operate the facilities. The 2011 period includes the Southern Pines Acquisition.

Financing Activities. Our financing activities for each of the periods listed above primarily relate to the funding of the investing activities discussed above along with the funding of purchases of hedged natural gas inventory. To fund these expenditures we made borrowings under our available credit facilities and received capital contributions from our equity owners. To fund the Southern Pines Acquisition, we issued an additional 27.6 million common units for total proceeds of approximately $600 million, including PAA s proportionate general partner contribution, and borrowed approximately $200 million from PAA.

Acquisitions, Capital Expenditures and Distributions to our Unitholders and General Partner

In addition to operating activities discussed above, we also use cash for our acquisition activities, purchases of natural gas inventory, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above.

Acquisitions. In February 2011, we completed the Southern Pines Acquisition for total consideration of approximately $765 million (approximately $750 million, net of cash and other working capital acquired).

Capital Expenditures. We currently forecast capital expansion expenditures for 2012 of approximately $54 million to $60 million (including capitalized interest), primarily related to the ongoing expansion of our Pine Prairie and Southern Pines facilities and the related base gas required to operate the facilities. We expect to fund our capital expenditures with cash generated from operations and borrowings under our credit agreement. Additionally, we are forecasting approximately $0.6 million of maintenance capital expenditures in 2012.

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Distributions to Unitholders and General Partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On February 14, 2012, we paid a quarterly distribution of $0.3575 per unit on our common units and Series A subordinated units.

Contingencies

For a discussion of contingencies that may impact us, see Note 13 to our consolidated financial statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we lease storage and transportation capacity from third parties, incur debt and interest payments and enter into purchase commitments in conjunction with our operations and our capital expansion program. Additionally, we purchase natural gas from third parties for both commercial and operational purposes. We establish a margin on gas purchased for commercial purposes by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. We do not expect to use a significant amount of internal capital on a long-term basis to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy.

	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt, interest and fees[(1)]	499.5	15.2	15.2	206.0	4.8	258.3	
Short-term borrowings	68.0	68.0					
Storage / transportation agreements and leases	27.2	14.0	6.6	4.5	2.0		0.1
Purchase obligations[(2)]	25.4	10.0	1.9	1.9	1.8	1.9	7.9
Other long-term liabilities	0.6	0.4	0.1	0.1			
Subtotal	620.7	107.6	23.8	212.5	8.6	260.2	8.0
Natural gas purchases[(3)]	74.6	74.6					
Total	695.3	182.2	23.8	212.5	8.6	260.2	8.0

(1) Includes interest payments and commitment fees on our senior unsecured credit agreement and note payable to PAA.
(2) Primarily includes amounts related to utility contracts and capital expansion activities.
(3) Amounts are based on estimated volumes and market prices based on committed obligations as of December 31, 2011. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit and Parental Guarantees. Our $450 million senior unsecured credit agreement provides us with the ability to issue letters of credit. In connection with our use of certain leased storage and transportation assets and the purchase of natural gas by our dedicated commercial marketing group, we have periodically provided certain suppliers and counterparties with irrevocable standby letters of credit to secure our obligations for such purchases. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our consolidated balance sheet in the month the services are provided or when we take delivery of the natural gas purchased. In certain instances, parental guarantees have been provided by PAA in lieu of letters of credit. As of December 31, 2011, we had approximately $3 million of outstanding letters of credit under our credit agreement. Additionally, approximately $31 million of parental guarantees issued by PAA on behalf of PNG Marketing were outstanding as of December 31, 2011.

Off-balance Sheet Arrangements

We do not have any off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

We use derivative instruments to manage our exposure to fluctuations in (i) natural gas prices associated with natural gas purchases and sales, crude oil prices associated with sales of crude oil produced from our Bluewater facility and (ii) interest rates. Our policy is to use derivative instruments only for risk management purposes. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, IntercontinentalExchange (ICE) and over-the-counter positions, as well as physical volumes, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

Storage Activities. 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 outright price of natural gas are not anticipated to 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. We also use derivative instruments to hedge the sale of all or some portion of our fuel-in-kind volumes in excess of actual volumes needed for our facilities. We may also purchase fuel in excess of our fuel-in-kind volumes to the extent such volumes are needed to operate our facilities.

Commercial Activities. Our dedicated commercial marketing group captures short-term market opportunities by utilizing a portion of our storage capacity for our own account and engaging in related commercial marketing activities. We conduct these commercial activities within pre-defined risk parameters, and our general policy is (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 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 are subject to commodity price risk, 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 as our risk procedures require that we maintain a balanced position as noted above.

Crude Oil Sales. We generate revenue through the sale of crude oil and natural gas 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. We use derivative instruments to hedge the sale of a portion of our crude oil production.

The fair value of our outstanding natural gas commodity derivatives as of December 31, 2011 was a net asset of approximately $16.1 million. A 10% decrease in natural gas prices would result in a net asset of approximately $20.3 million. A 10% increase in commodity prices would result in a net asset of approximately $11.9 million.

The fair value of our outstanding crude oil commodity derivatives as of December 31, 2011 was a net liability of approximately $0.3 million. A 10% increase or decrease in crude oil prices would not materially impact our financial statements.

Interest Rate Risk

Our $450 million five-year senior unsecured credit agreement bears interest based on a Eurodollar or Base Rate (as defined in the credit agreement) at our election, plus an applicable margin, which exposes us to risk associated with changes in market interest rates. We have entered into three interest rate swap agreements with an aggregate notional value of $100 million to fix the interest rate on a portion of the debt outstanding under our credit agreement.

The fair value of our outstanding interest rate swap agreements as of December 31, 2011 was a net liability of approximately $0.4 million. A 10% decrease in the forward LIBOR curve would result in a net liability of approximately $0.6 million. A 10% increase in the forward LIBOR curve would result in a net liability of approximately $0.2 million. The change in fair value of our interest rate swaps due to interest rate changes will be offset by higher or lower interest expense on our credit facility.

Item 8. ***Financial Statements and Supplementary Data***

See Index to the Consolidated Financial Statements on page F-1.

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that (1) information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms; and (2) information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report. Based on this review, our Chief Executive Officer and Chief Financial Officer have found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2011 and have found our process to be effective. See Management s Report on Internal Control Over Financial Reporting on page F-2.

Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Item 9B. ***Other Information***

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2011 that has not previously been reported.

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PART III

Item 10. ***Directors and Executive Officers of Our General Partner and Corporate Governance***
Partnership Management and Governance

Our general partner manages our operations and activities. The directors of our general partner oversee our operations. Unitholders are not entitled to elect our general partner or the directors of our general partner and do not participate in the management of our operations. Our partnership agreement limits any fiduciary duties our general partner might owe to our unitholders. 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.

We are majority owned and controlled by PAA and our assets, liabilities and results of operations are consolidated in PAA s financial statements. During 2011, our contribution to adjusted EBITDA represented less than 7% of PAA s consolidated adjusted EBITDA. The officers of our general partner are employed by PAA s general partner and manage the day-to-day affairs of our business. Certain of our officers devote substantially all of their time to managing our business, while other officers have responsibilities for both us and PAA and devote the majority of their time to PAA s other business activities. We 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 have entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed 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. The omnibus agreement does not increase or decrease our general partner s fiduciary duties to us under our partnership agreement. See Item 13. Certain Relationships and Related Transactions, and Director Independence for additional information regarding the omnibus agreement.

PAA is the sole member of our general partner and has the right to elect all seven members to the board of directors of our general partner. 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. In evaluating director candidates, PAA will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are commensurate with the board s responsibilities of managing and directing the affairs and business of the partnership, including, when applicable, enhancement of the ability of committees of the board to fulfill their duties.

Board Leadership Structure and Role in Risk Oversight

The board has no policy with respect to the separation of the offices of chairman and CEO. Currently, both positions are held by the CEO of PAA, the indirect general partner and majority equity holder in us. We do not have a lead independent director. 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 only to any specific unitholder rights contained in our partnership agreement. PAA has determined that the combined offices of Chairman and CEO represent an efficient and effective arrangement and that our leadership structure is appropriate in light of our ownership structure.

The management of enterprise-level risk (ELR) 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 ELR management, while the board has retained responsibility for oversight of management in that regard. Management provides an ELR assessment to the Board at least once every year.

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Non-Management Executive Sessions and Shareholder Communications

NYSE listing standards require regular executive sessions of the non-management directors of a listed company, and an executive session for independent directors at least once a year. Under the NYSE definition, only the members of our audit committee qualify as non-management as well as independent. Accordingly, our audit committee routinely holds discussions with no other directors or members of management present. These sessions are led by Mr. Burk, chairman of the audit committee. The board also routinely holds executive sessions that exclude those directors and officers who devote substantially all of their time to managing our business. Our non-management directors and those directors who are also officers, but who devote the majority of their time to PAA s other business activities, attend these sessions.

Interested parties can communicate directly with non-management directors by mail in care of the Vice President Legal and Business Development or in care of the Vice President of Internal Audit at PAA Natural Gas Storage, L.P., 333 Clay Street, Suite 1500, Houston, Texas 77002. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Independence Determination and Audit Committee

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. 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.

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 indirectly 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. The NYSE listing standards specify the criteria by which the independence of directors will be determined, including guidelines for directors and their immediate family members with respect to employment or affiliation with us or with our independent public accountants.

We have an audit committee that reviews our external financial reporting, engages our independent auditors, and reviews the adequacy of our internal accounting controls. The charter of our audit committee is available on our website. See Meetings and Other Information for information on how to access or obtain copies of this charter. The board of directors has determined that each member of our audit committee (Messrs. Burk, Shackouls and Smith) is independent under applicable NYSE rules and that Messrs. Burk and Smith are each an Audit Committee Financial Expert, as that term is defined in Item 407 of Regulation S-K.

In determining the independence of the members of our audit committee, the board of directors considered the relationships described below:

Victor Burk, chairman of our audit committee, is a managing director of Alvarez and Marsal, Inc., a business consulting firm that provides services from time to time to PAA and its affiliates, but not to PNG. Mr. Burk does not participate financially in the fees paid by PAA to Alvarez and Marsal. The board of directors of our general partner has determined that this relationship does not compromise the independence of Mr. Burk.

Bobby S. Shackouls, a member of our audit committee, has no relationship with us or our general partner, other than as a director.

Arthur L. Smith, a member of our audit committee, has no relationship with us or our general partner, other than as a director. Mr. Smith served on the board of directors of the general partner of PAA from February 1999 through December 2010.

For additional information regarding the experience and qualifications of our directors, see the biographical descriptions under Directors, Executive Officers and Other Officers of our General Partner below.

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Other Committees

Applicable NYSE listing standards do not require that we or our general partner have a compensation or nominating committee. Our general partner s board of directors performs the functions of a compensation committee and administers our Long Term Incentive Plan and other equity and executive compensation plans. The board of directors has the sole authority to retain any compensation consultants to be used to assist the board, but did not retain any consultants in 2011. Similarly, the board of directors has not delegated any of its authority to subcommittees. The board of directors has delegated limited authority to the CEO to administer our Long-Term Incentive Plan with respect to employees other than executive officers.

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.

Meetings and Other Information

During the last fiscal year, our board of directors had five meetings and our audit committee had eight meetings. None of our directors attended fewer than 75% of the aggregate number of meetings of the board of directors and committees of the board on which the director served.

As discussed above, the corporate governance of our general partner is, in effect, the corporate governance of our partnership and directors of our general partner are designated or elected by the sole member of our general partner, 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. As a result, we do not hold annual meetings of unitholders.

Our Audit Committee Charter and Governance Guidelines, as well as our Code of Business Conduct and our Code of Ethics for Senior Financial Officers, which apply to our principal executive officer, principal financial officer and principal accounting officer, are available on our Internet website at *http://www.pnglp.com*. We intend to disclose any amendment to or waiver of the Code of Ethics for Senior Financial Officers and any waiver of our Code of Business Conduct on behalf of an executive officer or director either on our Internet website or in an 8-K filing.

Audit Committee Report

The audit committee of our general partner oversees the Partnership s financial reporting process on behalf of the board of directors. Management has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

In fulfilling its oversight responsibilities, the audit committee reviewed and discussed with management the audited financial statements contained in this Annual Report on Form 10-K.

The Partnership s independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for expressing an opinion on the conformity of the audited financial statements with accounting principles generally accepted in the United States of America. The audit committee reviewed with PricewaterhouseCoopers LLP the firm s judgment as to the quality, not just the acceptability, of the Partnership s accounting principles and such other matters as are required to be discussed with the audit committee under generally accepted auditing standards.

The audit committee discussed with PricewaterhouseCoopers LLP the matters required to be discussed by Statement of Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board. The committee received written disclosures and the letter from PricewaterhouseCoopers LLP required by applicable requirements of the Public Company Accounting Oversight Board regarding PricewaterhouseCoopers LLP s communications with the audit committee concerning independence, and has discussed with PricewaterhouseCoopers LLP its independence from management and the Partnership.

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Based on the reviews and discussions referred to above, the audit committee recommended to the board of directors that the audited financial statements be included in the Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC.

Victor Burk, *Chairman*

Bobby S. Shackouls

Arthur L. Smith

Directors, Executive Officers and Other Officers of Our General Partner

The following table sets forth certain information with respect to the executive officers, directors, and certain other officers 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 12/31/2011)	Position with Our General Partner
Greg L. Armstrong*	53	Chairman of the Board, Chief Executive Officer and Director
Harry N. Pefanis*	54	Vice Chairman and Director
Dean Liollio*	53	President and Director
Al Swanson*	47	Executive Vice President, Chief Financial Officer and Director
Benjamin J. Reese	55	Senior Vice President Commercial
Todd Brown	46	Vice President Optimization
Richard K. McGee*	50	Vice President Legal and Business Development and Secretary
Dan Noack	41	Vice President Operations
Donald C. O Shea*	41	Controller and Chief Accounting Officer
Victor Burk	62	Director and Member of Audit Committee**
Bobby S. Shackouls	61	Director and Member of Audit Committee
Arthur L. Smith	59	Director and Member of Audit Committee

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

** Indicates chairman of committee.

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 and Chairman Pro Tem of the Federal Reserve Bank of Dallas, Houston Branch, and a director of National Oilwell Varco, Inc. Mr. Armstrong previously served as a director of BreitBurn Energy Partners, L.P. Mr. Armstrong is also a member of the advisory board of the Maguire Energy Institute at the Cox School of Business at Southern Methodist University, the National Petroleum Council and the Foundation for The Council on Alcohol and Drugs Houston. 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 brings 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, LLC. We believe that Mr. Pefanis extensive energy industry background, particularly the six 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, provides a critical resource and skill set to the board.

Al Swanson has served as Executive Vice President, Chief Financial Officer and Director of our general partner since July 2011 and as Executive Vice President and Chief Financial Officer of PAA s general partner since February 2011. He previously served as Senior Vice President, Chief Financial Officer and Director of our general partner from January 2010 until July 2011, as Senior Vice President and Chief Financial Officer of PAA s general partner from November 2008 until February 2011, 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 more than 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, lends significant financial and accounting experience and skill to the board.

Benjamin J. Reese has served as Senior Vice President Commercial of our general partner since June 2010. Mr. Reese has 30 years of experience in the natural gas industry. Prior to joining PNG, he was President of Sempra Midstream since October 2008. From 2007 to October 2008, Mr. Reese served as President and Chief Operating Officer of EnergySouth Midstream, Inc. the natural gas storage, pipeline transportation and midstream services subsidiary of EnergySouth, Inc., which was acquired by Sempra in October 2008. From 1998 to 2007, he served as Senior Vice President and Chief Commercial Officer for CenterPoint Energy. Prior to joining CenterPoint Energy, Mr. Reese spent 18 years in positions of increasing responsibility with USX-Delhi Pipelines and successor companies. Mr. Reese is a former board member of the National Energy Services Association and a current board member of the Southern Gas Association.

Todd Brown has served as Vice President Optimization of our general partner since June 2010. Mr. Brown has over 20 years of experience in the natural gas industry. Prior to joining PNG, he was Vice President Commercial of Sempra Pipelines & Storage since October 2008. From 2007 to October 2008, Mr. Brown served as Vice President Commercial of EnergySouth Midstream, Inc. From 2003 to 2007, he served as Vice President Natural Gas Trading for CenterPoint Energy. From 1988 to 2003, Mr. Brown served in various capacities in the natural gas businesses of several companies, including Mirant, Coral Energy, USX-Delhi Pipelines, Lone Star Gas and Santa Fe Minerals.

Richard K. 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. Mr. McGee has also served as Vice President and Deputy General Counsel of PAA s general partner since August 2011. 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.

Donald C. O Shea has served as Controller of our general partner since February 2010 and as Chief Accounting Officer since August 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 a Director of our general partner since April 2010. Since April 2009, Mr. Burk has been a Managing Director for Alvarez and Marsal, a privately owned professional services firm. 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 Management, LLC, the general partner of the general partner of EV Energy Partners, L.P., 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 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 State University, graduating with highest honors. The board of directors has determined that Mr. Burk is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. 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, brings valuable expertise and insight to the board.

Bobby S. Shackouls has served as a Director of our general partner since April 2010. Mr. Shackouls served as Chairman of Burlington Resources Inc. from 1997 until its acquisition by ConocoPhillips in 2006, and continued to serve as a director until his retirement in May 2011. He also served as President and Chief Executive Officer of Burlington Resources from 1995 until 2006. Mr. Shackouls currently serves as a director of The Kroger Co. The board of directors has determined that Mr. Shackouls is independent under applicable NYSE rules. 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.

Arthur L. Smith has served as a Director of our general partner since December 2010. Mr. Smith is President and Managing Member of Triple Double Advisors, LLC, an investment advisory firm focused on the energy industry. Mr. Smith was Chairman and CEO of John S. Herold, Inc. (a petroleum research and consulting firm) from 1984 to 2007. From 1976 to 1984, Mr. Smith was a securities analyst with Argus Research Corp., The First Boston Corporation and Oppenheimer & Co., Inc. Mr. Smith holds the Chartered Financial Analyst, or CFA, designation. He serves on the board of non-profit Dress for Success Houston. He is a director of Pioneer Natural Resources GP LLC, the general partner of Pioneer Southwest Energy Partners, L.P., and he served as a director of Plains All American GP LLC, the general partner of PAA, from February 1999 until December 2010. Mr. Smith received a BA from Duke University and an MBA from NYU s Stern School of Business. The board of directors has determined that Mr. Smith is independent under applicable NYSE rules and qualifies as an Audit Committee Financial Expert. In addition to his qualifications as an Audit Committee Financial Expert, Mr. Smith has more than 30 years of extensive and intensive experience in the energy sector as an oil analyst, prior board member (Parker & Parsley Petroleum Company, Cabot Oil & Gas Corporation, Evergreen Resources, Inc. and the New York Society of Security Analysts) and industry observer. We believe that his acute knowledge of the industry and his executive background provide a critical resource and skill set to the Board.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires directors, executive officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the NYSE initial reports of ownership and reports of changes in ownership of such equity securities. Such persons are also required to furnish us with copies of all Section 16(a) forms that they file. Such reports are accessible on or through our Internet website at *http://www.pnglp.com.*

Based solely upon a review of the copies of Forms 3 and 4 furnished to us, or written representations from certain reporting persons that no Forms 5 were required, we believe that our executive officers and directors complied with all filing requirements with respect to transactions in our equity securities during 2011.

Item 11. Executive Compensation
Compensation Committee Report

Our general partner s board of directors performs the functions of a compensation committee. The board of directors has reviewed and discussed with management the compensation discussion and analysis contained in this Annual Report on Form 10-K. Based on those reviews and discussions, the board of directors has recommended that the compensation discussion and analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2011 for filing with the SEC.

Greg L. Armstrong

Victor Burk

Dean Liollio

Harry N. Pefanis

Bobby S. Shackouls

Arthur L. Smith

Al Swanson

Compensation Committee Interlocks and Insider Participation

Our general partner s board of directors performs the functions of a compensation committee. Mr. Armstrong is a director, and Messrs. Armstrong, Pefanis and Swanson are executive officers, of the general partner of PAA. Messrs. Armstrong, Pefanis, Liollio and Swanson are officers of the company. All directors, including Messrs. Armstrong, Pefanis, Liollio and Swanson, participated in deliberations of the board concerning executive compensation during the last fiscal year; however, Mr. Liollio was not a participant in certain portions of the meetings during the discussion of his compensation.

Compensation Discussion and Analysis

Background

All of our executive officers and other personnel necessary for our business to function are 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 fiscal years prior to 2010. Our initial public offering was completed on May 5, 2010.

The board of directors of our general partner retains and exercises responsibility and authority for compensation-related decisions for executive officers who devote substantially all of their time to managing our business. The compensation committee of PAA s general partner retains and exercises responsibility and authority for compensation-related decisions for executive officers with shared responsibilities to both us and PAA, but who devote the majority of their time to PAA s other business activities. Our officers manage our business as part of the service provided by PAA under the omnibus agreement, and to the extent allocated to us and not otherwise excluded from reimbursement, the compensation for all of our executive officers is indirectly paid by us through reimbursements to PAA. Our general partner s board of directors is also responsible for the administration of our LTIP and other equity incentive programs and for compensation of our general partner s non-employee directors.

We are majority owned and controlled by PAA and our assets, liabilities and results of operations are consolidated in PAA s financial statements. During 2011, our contribution to adjusted EBITDA represented less than 7% of PAA s consolidated adjusted EBITDA. Messrs. Armstrong, Pefanis and Swanson are executive officers of the general partner of PAA and devote the majority of their time to PAA s other business activities. The activities of Messrs. Armstrong, Pefanis and Swanson with respect to PNG were a minor consideration for the compensation committee and board of directors of PAA in the determination of cash compensation paid to or equity incentives awarded to such individuals. Information relating to their compensation is set forth in PAA s Annual Report on Form 10-K. Accordingly, the following discussion relates primarily to the officers who devote substantially all of their time to our business activities and for whom the responsibility and authority for compensation related decisions reside directly with the board of directors of our general partner (the Dedicated Named Executive Officers). In

August 2011, Mr. McGee was appointed as a vice president of PAA and certain of his responsibilities at PNG have since been re-allocated to other PNG personnel. Beginning in 2012, it is expected that Mr. McGee will devote a majority of his time to PAA s other activities.

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Objectives

Similar to PAA, we employ a compensation philosophy that emphasizes pay-for-performance (primarily the ability to sustain and increase quarterly distributions to unitholders), both on an individual and entity level, and places the majority of each officer s compensation at risk. We believe our pay-for-performance approach aligns the interests of our executive officers with that of our unitholders, and at the same time enables us to maintain a lower level of base overhead in the event our operating and financial performance fails to meet expectations. Our executive compensation is designed to attract and retain individuals with the background and skills necessary to successfully execute our 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 our unitholders, and to reward success in reaching such goals. We use three primary elements of compensation to fulfill that design salary, cash bonuses 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 our 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. We do not maintain a defined benefit or pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance. PAA provides a basic benefits package that is generally available to all employees and 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, we will reimburse certain of our executive officers and other employees for club dues and similar expenses.

Elements of Compensation

Salary. We do not benchmark our salary or bonus amounts. In practice, we believe our salaries are generally competitive with the narrower universe of large-cap master limited partnerships, but are moderate relative to the broad spectrum of energy industry competitors for similar talent.

Cash Bonuses. Our cash bonuses consist of annual discretionary bonuses in which all of our Dedicated Named Executive Officers potentially participate and a quarterly bonus program in which Mr. Liollio was eligible to participate in 2011.

Long-Term Incentive Awards. The primary long-term measure of our performance is our ability to sustain and increase our quarterly distribution to our unitholders. We use performance-indexed phantom unit grants issued under our Long-Term Incentive Plan to encourage and reward timely achievement of targeted distribution levels and other performance conditions and align the long-term interests of our Dedicated Named Executive Officers and other members of our management team with those of our unitholders. In some cases, these grants also include a service period component in order to encourage long-term retention. A phantom unit is the right to receive, upon the satisfaction of vesting criteria specified in the grant, a common unit (or cash equivalent). We do not use options as a form of incentive compensation. Unlike vesting of an option, vesting of a phantom unit results in delivery of a common unit or cash of equivalent value as opposed to a right to exercise. Phantom units vest based upon the satisfaction of various criteria, which may include achievement of targeted distribution threshold levels or other performance conditions, or continued employment for periods ranging from two to five years. Distribution performance thresholds are generally consistent with our targeted range for distribution growth, as adjusted from time to time. Certain awards also include the right to receive distributions on phantom units prior to vesting in the underlying common units. These distribution equivalent rights are also referred to as DERs.

In 2010, our general partner authorized the creation of Class B units of PNGS GP LLC and authorized the board of directors to issue grants of Class B units to create additional long-term incentives for our management. The entire economic burden of the Class B units is borne solely by our general partner and does not impact our cash or units outstanding.

The Class B units are subject to restrictions on transfer and generally become incrementally earned (entitled to participate in distributions) upon achievement of certain performance thresholds. As of February 14, 2012, none of the Class B units granted in 2010 had been earned.

To encourage retention following achievement of these performance benchmarks, Class B units remain forfeitable (whether or not earned) if the holder terminates his employment prior to May 5, 2015. Additionally, the annual participation amount is capped to the maximum amount paid at the time of termination of employment, such that the holder does not benefit from growth in cash distributions experienced after the holder s employment terminates. See Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Our General Partner.

Transaction/Transition Grants. In connection with the initial public offering of PNG, PAA created a plan based on PNG equity, which is designed to reward and create incentive for certain of PAA s officers who were instrumental in developing the natural gas storage business and bringing it to the point of the IPO, and who will continue to allocate meaningful amounts of time to the business.

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Grants under this plan are awarded by the compensation committee of PAA s board, not by our board. In September 2010, PAA entered into transaction grant agreements with Messrs. Armstrong, Pefanis and Swanson, pursuant to which they acquired phantom common units, phantom series A subordinated units and phantom series B subordinated units representing a portion of the limited partner interest of PNG issued to PAA in connection with PNG s IPO. These grants were intended to be transactional and transitional and not a recurring component of these individual s compensation arrangements. Vesting terms were intended to align the interests of these individuals with those of PAA as such interests pertain to achieving specific future performance benchmarks that are significant to PNG and to PAA s equity holdings in PNG.

Relation of Compensation Elements to Compensation Objectives

Our compensation program is designed to motivate, reward and retain our executive officers. Cash bonuses serve as a near-term motivation and reward for achieving the annual goals established at the beginning of each year. Phantom unit awards (and associated DERs) and Class B units provide motivation and reward over both the near-term and long-term for achieving performance thresholds necessary for earning and vesting. Transaction/transition grants, as the title implies, focus on contributions to the success of a specific transaction, including reward for inception and consummation, as well as incentive for effective transition and execution of the business plan going forward. The level of annual bonus and phantom unit awards reflect the moderate salary profile and the significant weighting towards performance based, at-risk compensation. Salaries and cash bonuses (particularly quarterly bonuses), as well as currently payable DERs associated with unvested phantom units and earned Class B units subject to forfeiture upon termination by the holder, serve as near-term retention tools. Longer-term retention is facilitated by minimum service periods of up to five years associated with phantom unit awards, the long-term vesting profile of the Class B units and, in the case of certain executives, annual bonuses that are payable over a three-year period. To facilitate our general partner s board of directors in reviewing and making recommendations, a compensation tally sheet is prepared by our CEO and internal counsel and provided to the board for its review.

We stress performance-based compensation elements to attempt to create a performance-driven environment in which our executive officers are (i) motivated to perform over both the short term and the long term, (ii) appropriately rewarded for their services and (iii) encouraged to remain with us even after meeting long-term performance thresholds by the potential for rewards yet to come. We believe our compensation philosophy as implemented by application of the three primary compensation elements (i) aligns the interests of our Dedicated Named Executive Officers with our unitholders, (ii) positions us to achieve our business goals, and (iii) effectively encourages the exercise of sound judgment and risk-taking that is conducive to creating and sustaining long-term value. We believe the processes employed by the board in applying the elements of compensation (as discussed in more detail below) provide an adequate level of oversight with respect to the degree of risk being taken by management to achieve short-term performance goals. See Relation of Compensation Policies and Practices to Risk Management.

Application of Compensation Elements

Salary. We do not make systematic annual adjustments to the salaries of our Dedicated Named Executive Officers. We do, however, make salary adjustments as necessary to maintain hierarchical relationships among senior management levels after new senior management members are added to keep pace with our overall growth.

Annual Discretionary Bonuses. Annual discretionary bonuses are determined based on our performance relative to our annual plan forecast and public guidance (typically provided quarterly in conjunction with release of earnings), our distribution growth targets, and other quantitative and qualitative goals established at the beginning of each year. Such annual objectives are discussed and reviewed with the board of directors in conjunction with the review and authorization of the annual plan.

At the end of each year, the CEO performs a quantitative and qualitative assessment of our performance relative to our goals. Key quantitative measures include earnings before interest, taxes, depreciation and amortization, excluding items affecting comparability (adjusted EBITDA), relative to established guidance, as well as the level of the annualized quarterly distribution level per common unit relative to annual distribution targets. Our primary performance metric is our ability to sustain and increase quarterly cash distributions to our unitholders. Accordingly, although net income and net income per unit are monitored to highlight inconsistencies with primary performance metrics, as is our market performance relative to our MLP peers and major indices, these metrics are considered secondary performance measures. The CEO s written analysis of our performance examines our accomplishments, shortfalls and overall performance against opportunity, taking into account controllable and non-controllable factors encountered during the year.

The resulting document and supporting detail is submitted to the board of directors of our general partner for review and comment. Based on the conclusions set forth in the annual performance review, the CEO submits recommendations to the board of directors for bonuses to our Dedicated Named Executive Officers, taking into account the relative contribution of the individual officer. There are no set formulas for determining the annual discretionary bonus for our Dedicated Named Executive Officers. Factors considered by the CEO in determining the level of bonus in general include (i) whether or not we achieved the goals

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established for the year and any notable shortfalls relative to expectations; (ii) the level of difficulty associated with achieving such objectives based on the opportunities and challenges encountered during the year; (iii) current year operating and financial performance relative to both public guidance and prior year s performance; (iv) significant transactions or accomplishments for the period not included in the goals for the year; (v) our relative prospects at the end of the year with respect to future growth and performance; and (vi) our positioning at the end of the year with respect to our targeted credit profile. The CEO takes these factors into consideration as well as the relative contributions of each of our Dedicated Named Executive Officers to the year s performance in developing his recommendations for bonus amounts. These recommendations are submitted to the board of directors for its review and approval.

Quarterly Bonus Program. Mr. Liollio and certain other members of our management team are directly involved in activities that generate or significantly influence partnership earnings. These individuals, along with other employees in our commercial group, participate in a quarterly bonus pool, the size of which is based on adjusted EBITDA, which directly rewards for quarterly performance the commercial and asset managing employees who participate. This quarterly incentive provides a direct incentive to optimize quarterly performance even when, on an annual basis, other factors might negatively affect bonus potential. Mr. Liollio makes recommendations to Mr. Pefanis with respect to allocation of quarterly bonus amounts among all other participants based on relative contribution, and, after review and modification, if any, Mr. Pefanis submits recommendations to Mr. Armstrong for review, modification and approval, as appropriate. Messrs. Pefanis and Armstrong do not participate in the quarterly bonus program. The quarterly bonus amounts for Mr. Liollio are taken into consideration in determining the recommended annual discretionary bonus submitted by the CEO to the full board.

Long-Term Incentive Awards. Our Dedicated Named Executive Officers received phantom unit awards in connection with our initial public offering. We will not make systematic annual phantom unit awards to our Dedicated Named Executive Officers. Instead, our objective is to time the granting of awards such that as performance thresholds are met for existing awards, additional long-term incentives are created. Thus, performance is rewarded by relatively greater frequency of awards and lack of performance by relatively lesser frequency of awards. Generally, we believe that our awards are structured to provide a balance between a meaningful retention period for us and a visible, reachable reward for the executive officer. If top performance targets on outstanding awards are achieved in the early part of this cycle, new awards will be granted with higher performance thresholds, in a manner designed to encourage extended retention of our Dedicated Named Executive Officers and incentivize continued growth of our business. Accordingly, any new arrangements inherently take into account the value of awards where performance levels have been achieved but have not yet vested, but will not take into consideration previous awards that have fully vested.

As an additional means of providing longer-term, performance-based officer incentives that require extended periods of employment to realize the full benefit, our general partner authorized the creation of Class B units of PNGS GP LLC, which the board of directors is authorized to administer. See Elements of Compensation Long-Term Incentive Awards. These Class B units are limited to 165,000 authorized units, of which approximately 74,250 were outstanding as of December 31, 2011 pursuant to individual restricted units agreements between PNGS GP LLC and certain members of management. As of December 31, 2010, our Dedicated Named Executive Officers held 34,375 of the restricted Class B units. The remaining available Class B units are administered at the discretion of the board of directors and may be awarded upon advancement, exceptional performance or other change in circumstance of an existing member of management, or upon the addition of a new individual to the management team.

Application in 2011

At the beginning of 2011, PNG established the following goals:

1. Achieve or exceed plan;
2. Consummate, integrate and execute the Southern Pines acquisition per the acquisition forecast;
3. Execute consolidated capital plan on time and on budget and achieve targeted working capacity;
4. Refine and solidify PNG s acquisition screening, analysis and negotiation processes; and

5. Position PNG to achieve forecasted 2012 2015 results on an absolute and per unit basis.

In general and as discussed below, we met four of these five goals:

Our adjusted EBITDA exceeded the midpoint of our guidance for 2011 by approximately 3%. We also declared February, May and August annualized distributions of $1.38 per unit and achieved our revised publicly targeted exit rate for the November distribution of $1.43, which represents year-over-year growth of 5.9%.

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We completed the Southern Pines acquisition, integration was completed on schedule without encountering any major transition issues and overall results for Southern Pines for 2011 were in line with our acquisition forecast.

We executed our 2011 capital program on time and on or under budget, with development of net working gas capacity in line with 2011 guidance.

We conducted a thorough review and critique of our acquisition review, modeling, due diligence and integration processes and identified lessons learned and recommended process refinements.

With respect to the goal of repositioning PNG to achieve our forecasted performance for 2012-2015, such forecasts were adjusted downward during 2011 as a result of continued deterioration of the market outlook for natural gas storage. While the market forces that led to the failure to fully achieve this goal were not within our control, during 2011 we took a number of incremental steps that partially mitigated the impact of such market deterioration. These steps included (i) the expansion and extension of our credit facility on favorable terms, (ii) the acceleration of certain 2012 capital projects into 2011, and (iii) the development of various strategies to enhance marketing margin contributions.

For 2011, the elements of compensation were applied as described below.

Salary. In July 2011, the annual salary of Mr. O Shea was increased from $140,000 to $147,000. No other salary adjustments for Dedicated Named Executive Officers were recommended or made in 2011. See Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table.

Cash Bonuses. Based on the CEO s annual performance review and the individual performance of each of our Dedicated Named Executive Officers, the CEO recommended to the board of directors and the board of directors approved the annual bonuses reflected in the Summary Compensation Table and notes thereto. Such amounts take into account the performance relative to our 2011 goals; the absence or existence of shortfalls relative to expectations; the level of difficulty associated with achieving such objectives; our relative positioning at the end of the year with respect to future growth and performance; the significant transactions or accomplishments for the period not included in the goals for the year; and our positioning at the end of the year with respect to our targeted credit profile.

Long-Term Incentive Awards. During 2010, the board of directors granted two tranches of phantom unit awards to our Dedicated Named Executive Officers and other members of our senior management team that devote substantially all of their time to us. These grants were structured to encourage retention and align senior management s interests with the continued expansion of our business and the achievement of targeted levels of distribution growth based on our outlook for the gas storage business at that time. However, since the granting of such awards, there has been a fairly dramatic deterioration in gas storage market conditions that has adversely impacted our ability to achieve the distribution performance benchmarks set forth in the previous awards, regardless of management s performance. This, in turn, significantly reduced the extent to which the previous awards encouraged retention. In order to better align the interests of the recipients of such awards with our current outlook for the gas storage business and provide appropriate rewards that encourage retention in the current environment, in February 2012, the board of directors determined to modify the terms of the 2010 phantom unit awards. Phantom unit grants previously issued to Messrs. Liollio and O Shea were impacted by this modification. Mr. McGee s phantom unit grants were canceled in November 2011 in connection with his assumption of responsibilities at PAA.

As modified, the first tranche of phantom unit awards will vest as follows: 30% will vest on the date we pay an annualized distribution of $1.45 per unit; 30% will vest on the date we pay an annualized distribution of $1.50 per unit; and 40% will vest on the date we pay an annualized distribution of $1.55 per unit. Fifty percent of any unvested phantom units that remain outstanding as of the November 2016 distribution date will vest on such date and the remaining 50% will be forfeited. These awards have associated DERs that become payable 30% beginning in February 2012, 30% beginning in May 2013 and 40% beginning in May 2014.

Vesting terms of the second tranche of phantom unit awards have been modified to provide that 100% of the phantom units will vest upon conversion of our Series A Subordinated Units into Common Units. Conversion of the Series A Subordinated Units is subject to certain performance conditions set forth in our partnership agreement. Unvested phantom units that remain outstanding as of January 1, 2018 will expire. DERs associated with these awards accrue from February 2012 and are payable 50% on each distribution date in 2012 with the remaining 50% payable in February 2013. Beginning in February 2013, 100% of the DERs will become currently payable. The modified second tranche phantom unit awards also provide that in the event of a termination of employment other than for cause prior to the May 2013 distribution date, 50% of any outstanding phantom units will vest. If such termination occurs after the May 2013 distribution date, 100% of any outstanding phantom units will vest.

Upon vesting, the phantom units are payable on a one-for-one basis in common units. Associated DERs terminate when the underlying phantom units vest or are forfeited.

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Transaction/Transition Grants. No transaction/transition grants were awarded in 2011.

Other Compensation Related Matters

Equity Ownership in PNG. As of December 31, 2011, our Named Executive Officers beneficially owned, in the aggregate, approximately 221,872 of our common units (excluding any unvested equity awards), and 34,375 Class B units of our general partner. Although we encourage our Named Executive Officers to acquire and retain ownership in the Partnership, we do not have a policy requiring maintenance of a specified equity ownership level. In connection with the transaction/transition grants awarded in 2010, Messrs. Armstrong, Pefanis and Swanson indicated their intent to hold the common units they purchased in the IPO for a period of at least two years. Our policies prohibit our Named Executive Officers from using puts, calls or options to hedge the economic risk of their ownership.

Recovery of Prior Awards. Except as provided by applicable laws and regulations, we do not have a policy with respect to adjustment or recovery of awards or payments if relevant company performance measures upon which previous awards were based are restated or otherwise adjusted in a manner that would reduce the size of such award or payment.

Section 162(m). With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not fall within the definition of a corporation under Section 162(m).

Change in Control Triggers. The long-term incentive plan grants to our Dedicated Named Executive Officers and the Class B restricted units agreements include severance payment provisions or accelerated vesting triggered upon a change of control, as defined in the respective agreements. In the case of the long-term incentive plan grants, the provision becomes operative only if the change in control is accompanied by a change in status (such as the termination of employment by our general partner or PAA s general partner, as applicable). This double trigger arrangement provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. The Class B restricted units agreements generally call for vesting (upon a change in control) of any units that have already been earned, plus the next increment of units that could be earned at the next distribution threshold. Any remaining Class B restricted units would be forfeited (unless waived at the discretion of the general partner or acquirer as the case may be). See Potential Payments upon Termination or Change-in-Control. Messrs. Armstrong, Pefanis and Swanson have transaction/transition grants and other long-term incentives, and Messrs. Armstrong and Pefanis have employment agreements, that include provisions for a change in control of PAA, which are described in PAA s Annual Report on Form 10-K. The provision of severance or equity acceleration for certain terminations and change of control help to create a retention tool by assuring the executive that the benefit of the employment arrangement will be at least partially realized despite the occurrence of an event that would materially alter the employment arrangement.

Relation of Compensation Policies and Practices to Risk Management

Our compensation policies and practices reflect a similar philosophy and approach to that of PAA. Accordingly, such policies and practices are 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 our commercial marketing activities, 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 is 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 Item 7A. Quantitative and Qualitative Disclosures About Market Risk. We also routinely monitor and measure the execution and performance of our capital projects and acquisitions relative to expectations.

Our compensation arrangements contain a number of design elements that discourage taking of 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.

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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Summary Compensation Table

The following table sets forth certain compensation information for our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers in 2011 (our Named Executive Officers). We reimburse PAA for expenses incurred on our behalf, including the costs of PNG-related compensation paid to Messrs. Liollio, McGee and O Shea (excluding the costs of the obligations represented by applicable Class B units). PAA pushes down to us the compensation expense associated with the transaction/transition grants.

Because we were not capitalized before our May 2010 IPO, our compensation of personnel (including Named Executive Officers), did not commence until that time. Additionally, at the end of 2010, the annual bonus cycle for the Dedicated Named Executive Officers was shifted to a calendar year compensation cycle from a cycle coincident with the natural gas storage season (April 1 through March 31). For ease of presentation and future comparison, the amounts in the table below for 2010 include full calendar year amounts for salary, quarterly bonuses and all other compensation, but include annual bonuses for only the prorated period from April 1, 2010 to December 31, 2010. Information with respect to annual bonus compensation for our Dedicated Named Executive Officers for the 2009/2010 storage season that ended on March 31, 2010 is included in the footnotes to the table below.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)(1)	All Other Compensation ($)(2)	Total ($)
Greg L. Armstrong [3]	2011					
Chairman and Chief Executive Officer	2010			3,182,469		3,182,469[1]
Al Swanson [3]	2011					
Executive Vice President and Chief Financial Officer	2010			1,077,933		1,077,933[1]
Dean Liollio	2011	250,000	895,000[4][7]		15,900	1,160,900
President	2010	250,000	580,000[4][6][7]	409,095	15,900	1,254,995
Richard K. McGee	2011	200,000	475,000[5]		15,662	690,662
Vice President Legal and Business Development	2010	200,000	350,000[5][6][7]	214,288	15,660	779,948
Donald C. O Shea	2011	143,208	130,000		6,129	279,337
Controller and Chief Accounting Officer						

(1) Grant date fair values are presented for (i) transaction/transition grants awarded to Messrs. Armstrong and Swanson in 2010, and (ii) LTIP phantom unit grants and Class B restricted units granted to Messrs. Liollio and McGee in 2010 (the LTIP phantom units and Class B restricted units granted to Mr. McGee were canceled in November 2011 and the LTIP phantom units granted to Mr. Liollio were modified in February 2012). Dollar amounts represent the aggregate grant date fair value of transaction/transition grants, phantom units and Class B units granted during the year based on the probable outcome of underlying performance conditions pursuant to FASB ASC Topic 718. For transaction/transition grants awarded in 2010, vesting of 100% of the phantom common units and phantom series A subordinated units, and vesting of 20% of the phantom series B subordinated units, was deemed probable of occurrence on the grant date. For phantom units granted in 2010, none of the performance thresholds for vesting of the first tranche phantom units was deemed probable of occurrence as of the grant date, and 20% of the performance thresholds for vesting of the second tranche phantom units was deemed probable of occurrence as of the grant date. None of the performance thresholds for vesting of the Class B units was deemed probable of occurrence as of the grant date. The maximum grant date fair values of stock awards assuming that the highest level of performance conditions will be met are as follows:

Name	Year	Maximum Grant Date Fair Value ($)
Greg L. Armstrong	2011	
	2010	4,172,027
Al Swanson	2011	
	2010	1,413,106
Dean Liollio	2011	
	2010	4,389,057
Richard McGee	2011	
	2010	2,283,570
Don O Shea	2011	

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(2) Plains All American GP LLC matches 100% of employees contributions to its 401(k) plan in cash, subject to certain limitations in the plan. All Other Compensation for 2011 includes $14,700 in such contributions for each of Messrs. Liollio and McGee and $5,443 for Mr. O Shea. The remaining amount for each represents premium payments on behalf of such Named Executive Officer for group term life insurance.

(3) Messrs. Armstrong and Swanson are also executive officers of and are compensated by PAA, with a portion of the costs associated with such overhead being allocated to us under the omnibus agreement. Total compensation for each of Messrs. Armstrong and Swanson, as reported in PAA s Annual Report on Form 10-K for the year ended December 31, 2011, was $5,390,900 and $2,015,900, respectively. PAA s 2011 Annual Report on Form 10-K is available on its website at *www.paalp.com*.

(4) Includes quarterly bonuses aggregating $333,000 and $330,000, and annual bonuses of $562,000 and $250,000 for 2011 and 2010, respectively. The amount in the table for 2010 does not reflect (i) a $325,000 annual bonus awarded in the second quarter of 2010 for the 2009/2010 storage season, and (ii) a special bonus of $800,000 awarded in January 2010 (generally attributable to 2009) for Mr. Liollio s efforts in connection with our preparation for the IPO.

(5) For his services in connection with acquisition activities at PAA, $200,000 of Mr. McGee s annual bonus for 2011 was paid by PAA. For his efforts in connection with our IPO, $200,000 of Mr. McGee s annual bonus for 2010 was paid by PAA. The amount in the table for 2010 does not reflect a $175,000 annual bonus awarded in the second quarter of 2010 for the 2009/2010 storage season, which amount was prorated from his date of employment.

(6) The 2010 annual bonuses for Messrs. Liollio and McGee were prorated to reflect a shift at the end of 2010 from a compensation cycle tied to the natural gas storage season (April 1 through March 31), to a calendar year cycle. As a result, the annual bonus amounts included in the table for 2010 are for the period from April 1, 2010 to December 31, 2010.

(7) Annual bonuses are payable 60% at the time of award and 20% in each of the two succeeding years.

Grants of Plan-Based Awards Table

There were no grants of plan-based awards to our Named Executive Officers during the fiscal year ended December 31, 2011.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

A discussion of 2011 salaries and bonuses for our Dedicated Named Executive Officers and how they fit into the overall compensation array is included in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table and Grants of Plan-Based Awards Table above.

Salary As discussed in this Item 11, we do not make systematic annual adjustments to the salaries of our Dedicated Named Executive Officers. In that regard, no salary adjustments were made for any of our Dedicated Named Executive Officers in 2011, other than Mr. O Shea whose salary was increased from $140,000 to $147,000.

Grants of Plan-Based Awards None of our Dedicated Named Executive Officers received grants under our long-term incentive plan in 2011. In November 2011, Mr. McGee s previously awarded grants of phantom units and Class B units were canceled. In connection with his new responsibilities at PAA, Mr. McGee received grants of phantom units under PAA s long-term incentive plan and Class B units of Plains AAP, L.P. In February 2012, phantom units previously granted to Messrs. Liollio and O Shea were modified. See Compensation Discussion and Analysis Application in 2011 Long-Term Incentive Awards for further information regarding the 2012 modifications.

Transaction/Transition Grants No transaction/transition grants were awarded in 2011.

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Employment Agreements

In connection with his employment in November 2008, Mr. Liollio and PAA entered into an employment agreement, which provided, among other things, for (i) an annual salary of $250,000, (ii) an annual target bonus of 225% of his base salary, and (iii) the grant of phantom units. 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 received an annual bonus of $250,000 that included a prorated amount for his 2008/2009 storage season service (from commencement of his employment in November 2008 through March 31, 2009). Mr. Liollio received an annual bonus in the second quarter of 2010 for his 2009/2010 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. This grant was subsequently replaced with a grant under our Long-Term Incentive Plan. Pursuant to its terms, Mr. Liollio s employment agreement expired in November 2011.

In connection with his employment in September 2009, Mr. McGee and PAA entered into an employment agreement, which provided, among other things, for (i) an annual salary of $200,000, (ii) an annual target bonus of 150% of his base salary, and (iii) the grant of phantom units. During 2009, Mr. McGee was paid approximately $59,000 in the form of pro-rated salary and he received an annual bonus in the second quarter of 2010 that included a prorated amount for his 2009/2010 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. This grant was subsequently replaced with a grant under our Long-Term Incentive Plan and then canceled in connection with his transition to PAA.

Employment agreements for Messrs. Armstrong and Pefanis are described in PAA s annual report on Form 10-K.

Outstanding Equity Awards at Fiscal Year-End

The following table sets forth certain information with respect to outstanding equity awards at December 31, 2011 with respect to our Named Executive Officers:

	Unit Awards			
Name	**Number of Shares or Units of Stock That Have Not Vested (#)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)(1)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)**
Greg L. Armstrong	31,000(2)	581,250		
			62,000(3)	1,162,500
			62,000(4)	1,162,500
Al Swanson	10,500(2)	196,875		
			21,000(3)	393,750
			21,000(4)	393,750
Dean Liollio			105,000(5)	1,968,750
			105,000(6)	1,968,750
			34,375(7)	352,866
Richard K. McGee				

Don O Shea	7,500(5)	140,625
	7,500(6)	140,625

(1) Market value of PNG phantom units and transaction/transition grants reported in these columns is calculated by multiplying the closing market price ($18.75) of our common units at December 30, 2011 (the last trading day of the fiscal year) by the number of units. No discount is applied for remaining performance threshold or service period requirements. The Class B units are valued based on the grant date fair value computed in accordance with FASB ASC Topic 718 assuming that the highest level of performance conditions will be met.

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(2) Represents the balance of phantom common units under transaction/transition grants. These phantom common units will vest on May 5, 2012, and be payable one-for-one by PAA in Common Units of PNG.

(3) Represents phantom series A subordinated units under transaction/transition grants. These phantom series A subordinated units will vest in connection with the conversion of the Series A Subordinated Units into Common Units, and be payable one-for-one by PAA in Common Units of PNG. Any of these phantom series A subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.

(4) Represents phantom series B subordinated units under transaction/transition grants. These phantom series B subordinated units will vest in increments of 20%, 21%, 15%, 22% and 22%, respectively, in connection with the conversion of the First through Fifth Tranches of Series B Subordinated Units. Upon vesting, the phantom series B subordinated units will be payable one-for-one by PAA in Series A Subordinated Units or Common Units of PNG it receives upon conversion of the Series B Subordinated Units. Any of these phantom series B subordinated units that have not vested as of December 31, 2018 will be automatically cancelled on such date.

(5) Represents the first tranche of phantom units granted in 2010 under our Long Term Incentive Plan. Pursuant to vesting terms in effect as of December 31, 2011, these phantom units would have vested as follows: one-third upon the later of the May 2012 distribution date and payment of an annualized distribution of $1.55; one-third upon the later of the May 2013 distribution date and payment of an annualized distribution of $1.80; and one-third upon the later of the May 2014 distribution date and payment of an annualized distribution of $1.90. DERs associated with these phantom units would have vested in 25% increments upon payment of annualized distributions of $1.48, $1.56, $1.76 and $1.90. The vesting terms of these phantom units were modified in February 2012. As modified, these phantom unit awards will vest 30% on the date we pay an annualized distribution of $1.45 per unit; 30% on the date we pay an annualized distribution of $1.50 per unit; and 40% on the date we pay an annualized distribution of $1.55 per unit. Fifty percent of any unvested phantom units that remain outstanding as of the November 2016 distribution date will vest on such date and the remaining 50% will be forfeited. These awards have associated DERs that become payable 30% beginning in February 2012, 30% beginning in May 2013 and 40% beginning in May 2014. Upon vesting, the phantom units are payable on a one-for-one basis in common units. Associated DERs terminate when the underlying phantom units vest or are forfeited.

(6) Represents the second tranche of phantom units granted in 2010 under our Long Term Incentive Plan. Pursuant to vesting terms in effect as of December 31, 2011, these phantom units would have vested as follows: 20% upon conversion of our Series A Subordinated Units into Common Units; 20% upon conversion of the first tranche of our Series B Subordinated Units; 20% upon conversion of the second tranche of our Series B Subordinated Units; 20% upon conversion of the third tranche of our Series B Subordinated Units; and 20% upon conversion of the fourth tranche of our Series B Subordinated Units. The vesting terms of these phantom units were modified in February 2012. As modified, 100% of the phantom units will vest upon conversion of our Series A Subordinated Units into Common Units. Conversion of the Series A Subordinated Units is subject to certain performance conditions set forth in our partnership agreement. Unvested phantom units that remain outstanding as of January 1, 2018 will expire. DERs associated with these awards accrue from February 2012 and are payable 50% on each distribution date in 2012 with the remaining 50% payable in February 2013. Beginning in February 2013, 100% of the DERs will become currently payable. Upon vesting, the phantom units are payable on a one-for-one basis in common units. Associated DERs terminate when the underlying phantom units vest or are forfeited.

(7) Represents Class B units of PNGS GP LLC. Each Class B unit represents a profits interest in PNGS GP LLC, which entitles the holder to participate in future profits and losses from operations, current distributions from operations, and an interest in future appreciation or depreciation in PNGS GP LLC s asset values, but does not represent an interest in the capital of PNGS GP LLC on the applicable grant date of the Class B units. As of December 31, 2011, none of the Class B units had been earned or vested. For additional information regarding the Class B units, see Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Class B Units of Our General Partner.

Pension Benefits

PAA sponsors a 401(k) plan that is available to all U.S. employees, but neither we nor PAA maintain a pension or defined benefit program.

Nonqualified Deferred Compensation and Other Nonqualified Deferred Compensation Plans

Neither we nor PAA have a nonqualified deferred compensation plan or program for our officers or employees.

Potential Payments upon Termination or Change-in-Control

The following table sets forth potential amounts payable to the Dedicated Named Executive Officers upon termination of employment under various circumstances, and as if terminated on December 31, 2011. Potential amounts payable with respect to equity awards are based on the terms of phantom unit awards outstanding at December 31, 2011. The terms of such awards were modified in February 2012. Information with respect to potential payments to Messrs. Armstrong and Swanson upon termination of employment is contained in PAA s Annual Report on Form 10-K for the year ended December 31, 2011.

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	By Reason of Death ($)	By Reason of Disability ($)	By Company without Cause ($)	By Executive with Good Reason ($)	In Connection with a Change In Control ($)
Dean Liollio					
Equity Compensation (1)(2)(3)	787,500	787,500	N/A	N/A	3,937,500
Class B Units (4)	N/A	N/A	N/A	N/A	162,856
Total	787,500	787,500	N/A	N/A	4,100,356
Richard K. McGee					
Equity Compensation (1)	N/A	N/A	N/A	N/A	N/A
Class B Units (4)	N/A	N/A	N/A	N/A	N/A
Total	N/A	N/A	N/A	N/A	N/A
Don O Shea					
Equity Compensation (1)(2)(3)	56,250	56,250	N/A	N/A	281,250
Total	56,250	56,250	N/A	N/A	281,250

(1) The letters evidencing the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 provided that in the event of their death or disability (as defined below), all of their then outstanding phantom units and any associated DERs would be deemed nonforfeitable, and (i) any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would vest on the next following distribution date and (ii) the remaining unvested outstanding phantom units would vest on the distribution date on which the vesting criteria is met. For this purpose disability means a physical or mental infirmity that impairs the ability substantially to perform duties for a period of eighteen (18) months or that the general partner otherwise determines constitutes a disability. Assuming that death or disability occurred on December 31, 2011, all phantom units and the associated DERs held by Messrs. Liollio and O Shea would have become nonforfeitable effective as of December 31, 2011, and would have vested according to vesting terms in effect on such date as described in footnotes 5 and 6 to the Outstanding Equity Awards at Fiscal Year-End table.

The dollar value given assumes that all performance thresholds would be timely achieved if deemed probable of occurrence as of December 31, 2011, and is based on the market value of PNG s common units on December 31, 2011 ($18.75 per unit) without discount for service period. At December 31, 2011, an annualized distribution level of $1.45, conversion of the series A subordinated units and conversion of the first tranche of series B subordinated units were deemed probable of occurrence. As a result, none of the first tranche phantom unit grants were assumed to eventually vest, and 40% of the second tranche phantom unit grants were assumed to eventually vest.

The terms of the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 were subsequently modified in February 2012. See Compensation Discussion and Analysis Application in 2011 Long-Term Incentive Awards for more information regarding this modification. Mr. McGee s phantom units were canceled in November 2011.

(2) The letters evidencing the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 provided that in the event their employment is terminated other than in connection with a change in control (as defined in Footnote 3 below) or by reason of death, disability (as defined in Footnote 1 above), all of the phantom units and any associated DERs (regardless of vesting) then outstanding under such phantom unit grants would automatically be forfeited as of the date of termination; provided, however, that if their employment is terminated other than for cause (as defined in footnote 3 below), any unvested phantom units that had satisfied all of the vesting criteria as of the date of their termination but for the passage of time would be deemed nonforfeitable and would vest on the next following distribution date. Assuming that Messrs. Liollio and O Shea had been terminated without

cause on December 31, 2011, all of their phantom units would have been forfeited. The terms of the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 were subsequently modified in February 2012. See Compensation Discussion and Analysis Application in 2011 Long-Term Incentive Awards for more information regarding this modification.

(3) The letters evidencing the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 provided that in the event of a change of status (as defined below), all of the then outstanding phantom units and associated DERs would be deemed nonforfeitable, and such phantom units would vest in full (i.e., the phantom units would become payable in the form of one common unit per phantom unit) upon the next following distribution date. Assuming the change in status occurred on December 31, 2011, all outstanding phantom units and the associated DERs would have become nonforfeitable as of such date, and such phantom units would have vested on February 14, 2012. The dollar value given is based on the market value of PNG s common units on December 31, 2011 ($18.75 per unit) without discount for service period. The terms of the phantom unit grants held by Messrs. Liollio and O Shea on December 31, 2011 were subsequently modified in February 2012. See Compensation Discussion and Analysis Application in 2011 Long-Term Incentive Awards for more information regarding this modification.

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The phrase change in status means the occurrence, during the period beginning two and a half months prior to and ending one year following a change of control (as defined below), of any of the following: (A) the termination of employment by the general partner other than a termination for cause (as defined below), or (B) the termination of employment by such officer due to the occurrence, without his written consent, of (i) any material diminution in such officer s authority, duties or responsibilities, (ii) any material reduction in such officer s base salary or (iii) any other action or inaction that would constitute a material breach of the agreement by Plains All American GP LLC.

The phrase change of control means, and is deemed to have occurred upon the occurrence of, one or more of the following events: (i) PAA ceasing to retain direct or indirect control of our general partner; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of PNG or PNGS GP LLC to any person and/or its affiliates, other than to us, PNGS GP LLC or PAA, including any employee benefit plan thereof; (iii) the consolidation, reorganization, merger, or any other similar transaction involving (A) a person other than us, PNGS GP LLC or PAA and (B) us, PNGS GP LLC or both; or (iv) any person, including any partnership, limited partnership, syndicate or other group deemed a person for purposes of Section 13(d) or 14(d) of the Securities Exchange Act of 1934, as amended, becoming the beneficial owner, directly or indirectly, of more than 49.9% of the membership interest in PNGS GP LLC. Notwithstanding the definition of change of control, no change of control is deemed to have occurred in connection with a restructuring or reorganization related to the securitization and sale to the public of direct or indirect equity interests in our general partner if PAA continues to have the power to elect, directly or indirectly, the majority of the board of directors of our general partner.

The term cause means (i) the failure to perform a job function in accordance with standards described in writing, or (ii) the violation of the general partner s Code of Business Conduct (unless waived in accordance with the terms thereof), in each case, with the specific failure or violation described in writing.

(4) Pursuant to the Class B Restricted Units Agreements, upon the occurrence of a Change in Control (defined below), any earned Class B units (and any Class B units that will become earned in less than 180 days) become vested units and, to the extent any Class B units remain unearned, an incremental 25% of the number of Class B units originally granted becomes vested. As of December 31, 2011, none of the Class B units held by Mr. Liollio had been earned or will become earned in less than 180 days. Assuming a Change in Control on December 31, 2011, 25% of the Class B units held by Mr. Liollio would become vested. The value of such Class B units as reflected in the table is derived in accordance with FASB ASC Topic 718. Mr. McGee s Class B units were canceled in November 2011.

Change in Control means the determination by the Board that one of the following events has occurred: (i) PNGS GP LLC ceases to retain direct or indirect control over the Partnership; (ii) PAA and its affiliates (the Owner Affiliates) cease to own directly or indirectly at least 50% of the member interests of PNGS GP LLC; (iii) a person or group (as such terms are used in Sections 13(d) and 14(d) of the Exchange Act) becomes after the Grant Date the beneficial owner (as defined in Rules 13(d)-3 and 13(d)-5 under the Exchange Act), directly or indirectly, of more than 50% of the member interest of PNGS GP LLC; or (iv) a transfer, sale, exchange or other disposition in a single transaction or series of transactions (whether by merger or otherwise) of all or substantially all of the assets of PNGS GP LLC or the Partnership to one or more persons who are not Affiliates of PNGS GP LLC, other than a transaction in which the Owner Affiliates become the beneficial owners, directly or indirectly, of more than 50% of the voting power of such person or persons immediately following such transaction.

Confidentiality, Non-Compete and Non-Solicitation Arrangements

Messrs. Liollio and McGee have agreed to maintain the confidentiality of PAA and PNG information for a period of two years after the termination of their employment. They have also agreed not to solicit customers or employees for a period of two years following termination of their employment.

Compensation of Directors

The following table sets forth a summary of the compensation paid to each person who served as a non-employee director of our general partner in 2011:

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($) (1)	Total ($)
Victor Burk	65,000	69,750	134,750
Bobby S. Shackouls	55,000	69,750	124,750
Arthur L. Smith	55,000	398,175	453,175

(1) The dollar value of LTIPs granted during 2011 is based on the grant date fair value computed in accordance with FASB ASC Topic 718. In connection with the August 2011 vesting of director LTIP awards, Messrs. Burk and Shackouls each were granted 3,750 units and Mr. Smith was granted 1,875 units by virtue of the automatic re-grant feature of the vested awards. In addition to the automatic re-grant in August, Mr. Smith received an initial grant of 15,000 LTIPs in February 2011. As of December 31, 2011, the number of outstanding LTIPs held by Messrs. Burk, Shackouls and Smith was 15,000 each.

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Each director of PNGS GP LLC who is not an employee of Plains All American GP LLC is reimbursed for any travel, lodging and other out-of-pocket expenses related to meeting attendance or otherwise related to service on the board (including, without limitation, reimbursement for continuing education expenses). Each non-employee director is paid an annual retainer fee of $40,000. Messrs. Armstrong, Pefanis, Swanson and Liollio are otherwise compensated for their services as employees and therefore receive no separate compensation for their services as directors. In addition to the annual retainer, the chairman of the audit committee receives $25,000 annually, and the other members of the audit committee receive $15,000 annually, in each case, in addition to the annual retainer. During 2011, Mr. Burk served as chairman of the audit committee.

Our non-employee directors receive LTIP awards as part of their compensation. The LTIP awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The awards have associated distribution equivalent rights that are payable quarterly.

All LTIP awards held by a director vest in full upon the next following distribution date after the death or disability (as determined in good faith by the board) of the director. The awards also vest in full if such director (i) retires (no longer with full-time employment and no longer serving as an officer or director of any public company) or (ii) is removed from the board of directors or is not reelected to the board of directors, unless such removal or failure to reelect is for good cause, as defined in the letter granting the units.

Each director will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

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

Our common units and series A and series B subordinated units outstanding represent 98% of our equity (limited partner interest). The 2% general partner interest and all of our incentive distribution rights are owned by our general partner, PNGS GP LLC. The following table sets forth the beneficial ownership of limited partner units held by beneficial owners of 5% or more of the units, directors, the Named Executive Officers, and all directors and executive officers as a group as of February 15, 2012.

Name of Beneficial Owner	Common Units	Percentage Of Common Units	Series A Subordinated Units	Percentage of Series A Subordinated Units	Series B Subordinated Units	Percentage of Series B Subordinated Units	Percentage of Total Common and Subordinated Units
Plains All American Pipeline, L.P. 333 Clay Street, Suite 1600 Houston, TX 77002	28,214,198	47.7%	11,934,351	100%	13,500,000	100%	63.4%
Janus Capital Management LLC 151 Detroit St. Denver, CO 80206	4,223,629(1)	7.1%					5.0%
Richard A. Kayne/Kayne Anderson Capital Advisors, L.P. 1800 Avenue of the Stars, Third Floor Los Angeles, CA 90067	3,720,371(2)	6.3%					4.4%
Greg L. Armstrong	131,000(3)(4)	*					*
Harry N. Pefanis	96,000(3)	*					*
Al Swanson	44,172(3)	*					*
Dean Liollio	26,700(5)	*					*
Richard K. McGee	20,000	*					*
Don O Shea							
Victor Burk	5,688(5)	*					*
Bobby S. Shackouls	4,688(5)	*					*
Arthur L. Smith	1,875(5)	*					*
All directors and executive officers as a group (9 persons)	330,123(5)(6)	*					*

* Less than 1%

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(1) This information has been derived from a Schedule 13G filed with the SEC on February 14, 2012.

(2) This information has been derived from a Schedule 13G filed with the SEC on February 7, 2012. Based on the information contained in the filing, Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have shared voting power and dispositive power with respect to, and beneficially own, an aggregate of 3,709,371 common units. Mr. Kayne has sole voting power and dispositive power with respect to, and beneficially owns, 11,000 common units.

(3) Does not include unvested phantom units under transaction/transition grants, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End.

(4) Does not include common and subordinated units owned by Plains All American Pipeline, L.P. Mr. Armstrong is Chairman of the Board, Chief Executive Officer and a Director of PAA s general partner. He disclaims any beneficial ownership of PAA s interest in PNG.

(5) Does not include unvested phantom units granted under our Long-Term Incentive Plan, none of which will vest within 60 days of the date hereof. See Item 11. Executive Compensation Outstanding Equity Awards at Fiscal Year-End and Director Compensation.

(6) As of February 15, 2012, no units were pledged by directors or Named Executive Officers. Certain of the directors and Named Executive Officers hold units in marginable broker s accounts, but none of the units were margined as of February 15, 2012.

Equity Compensation Plan Information

The following table sets forth certain information with respect to our equity compensation plans as of December 31, 2011. For a description of these plans, see Item 13. Certain Relationships and Related Transactions, and Director Independence Our General Partner Equity-Based Long-Term Incentive Plan.

Plan Category	Number of Units to be Issued upon Exercise/Vesting of Outstanding Options, Warrants and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Units Remaining Available for Future Issuance under Equity Compensation Plans (c)
Equity compensation plans approved by unitholders:			
Long Term Incentive Plan	490,000(1)	N/A(2)	2,498,749(1)(3)
Equity compensation plans not approved by unitholders:			
N/A			

(1) The Long Term Incentive Plan was approved by our unitholders in April 2010. The LTIP contemplates the issuance or delivery of up to 3,000,000 units to satisfy awards under the plan. The number of units presented in column (a) assumes that all outstanding grants will be satisfied by the issuance of new units upon vesting unless such LTIPs are by their terms payable only in cash. In fact, some portion of the phantom units may be settled in cash and some portion will be withheld for taxes. Any units not issued upon vesting will become available

for future issuance under column (c).

(2) Phantom unit awards under the LTIP vest without payment by recipients.

(3) In accordance with Item 201(d) of Regulation S-K, column (c) excludes the securities disclosed in column (a). However, as discussed in footnote (1), any phantom units represented in column (a) that are not satisfied by the issuance of units become available for future issuance.

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

For a discussion of director independence, see Item 10. Directors and Executive Officers of Our General Partner and Corporate Governance.

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Our General Partner

Our operations and activities are managed by our general partner. The officers of our general partner are employed by PAA s general partner and manage the day-to-day affairs of our business. Certain of our officers devote a substantial portion of their time to managing our business, while other officers have responsibilities for both us and PAA. We 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 reimburse PAA for all expenses incurred on our behalf (other than expenses related to the Class B units of our general partner). Total costs reimbursed by us to PAA for the year ended December 31, 2011 were approximately $15.2 million.

Our general partner owns the 2% general partner interest and all of the incentive distribution rights. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.3375 ($1.35 annualized) per unit, 25% of the amounts we distribute in excess of $0.37125 ($1.485 annualized) per unit and 50% of amounts we distribute in excess of $0.50625 ($2.025 annualized) per unit.

The following table illustrates the allocation of aggregate distributions at different per-unit levels (dollars in thousands):

Annual LP Distribution Per Unit	Distribution to LP Unitholders(1)	Distribution to GP(1)(2)	Total Distribution(1)(2)	GP % of Total Distribution
$1.35	$ 96,023	$ 1,960	$ 97,983	2.0%
$1.40	$ 99,580	$ 2,587	$ 102,167	2.5%
$1.45	$ 103,136	$ 3,215	$ 106,351	3.0%
$1.50	$ 106,692	$ 4,010	$ 110,702	3.6%
$1.55	$ 110,249	$ 5,195	$ 115,444	4.5%
$1.60	$ 113,805	$ 6,381	$ 120,186	5.3%
$1.65	$ 117,362	$ 7,566	$ 124,928	6.1%

(1) Based on 71,128,176 Common Units and Series A Subordinated Units outstanding at February 22, 2012. Does not include Series B Subordinated Units. An increase in the number of units outstanding would increase both the distribution to unitholders and the distribution to the general partner for any given level of distribution per unit.

(2) Includes distributions attributable to the 2% general partner interest and the incentive distribution rights.

Equity-Based Long-Term Incentive Plan

In April 2010, our general partner 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. Awards contemplated under the Plan include 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 is administered by the board of directors 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.

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. The plan administrator determines to make grants of phantom units under the Long Term Incentive Plan containing such terms as the plan administrator determines.

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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.

The issuance of common units upon vesting of the phantom units under the Long Term Incentive Plan is intended primarily 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.

Other Awards. The Long Term Incentive Plan also permits the grant of restricted units, unit options, unit appreciation rights and unit awards. No such awards have been granted to date.

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.

Class B Units of Our General Partner

Our general partner has authorized the issuance to members of our management team Class B units, each representing a profits interest in our general partner. The Class B units are 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 is borne solely by our general partner. We are not 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.

As of December 31, 2011, 74,250 Class B units were issued and outstanding out of 165,000 authorized. The outstanding Class B units are subject to restrictions on transfer and generally become earned (entitled to participate in distributions) in percentage increments when the annualized quarterly distributions on our common units equal or exceed certain thresholds. Class B units become earned in 25% increments 180 days after we pay annualized quarterly distributions on our common units of $2.00, $2.30, $2.50 and $2.70. Earned Class B units will be entitled to their proportionate share of all quarterly cash distributions made by our general partner in excess of $2.5 million per quarter. Fifty percent of earned units will vest immediately upon becoming earned and 50% will vest on the fifth anniversary of the date of grant. Any Class B units that are earned after the fifth anniversary of the date of grant will fully vest upon becoming earned. Assuming all authorized Class B units are issued, the maximum participation would be 6% of the amount in excess of $2.5 million per quarter. As of December 31, 2011, none of the Class B units had been earned.

To encourage retention following achievement of these performance benchmarks, Class B units remain forfeitable (whether or not earned) if the holder terminates his employment prior to May 5, 2015. Additionally, the participation amount is capped to the maximum amount paid at the time of termination of employment, such that the holder does not benefit from growth in cash distributions experienced after the holder s employment terminates. Upon the occurrence of a change of control (as defined), (i) all earned units will vest, and (ii) to the extent any of the units are unearned at the time, an incremental 25% of the units originally awarded will vest. All earned Class B units will also vest if they remain outstanding as of May 5, 2015.

Related Party Transactions

Omnibus Agreement

In May 2010, we entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed upon certain aspects of our relationship with PAA, including, among other things (1) 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, (2) the provision by PAA s general partner of such personnel 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 personnel, (3) certain indemnification obligations, and (4) our use of the name PAA and related marks. Under this agreement, PAA indemnifies us against certain environmental liabilities, tax matters, and title or permitting defects generally for a period of three years after the closing of our initial public offering. The environmental indemnifications are subject to a cap of $15 million and require us to pay the first $250,000 of costs incurred. In addition, we have indemnified PAA against any losses, costs or damages incurred by PAA or its general partner that are attributable to the ownership and operation of our assets following the closing of our initial public offering.

Tax Sharing Agreement

In May 2010, we entered into a tax sharing agreement with PAA, pursuant to which we and PAA agreed 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 our IPO.

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. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guarantees or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us.

During 2011, PAA issued $31 million of parental guarantees to third parties on behalf of PNG Marketing. We pay a minimum quarterly fee of $12,500 to PAA to cover PAA s administrative costs of providing such guarantees. During the year ended December 31, 2011, we incurred approximately $0.1 million of expense under our obligation to reimburse PAA for administrative costs incurred in conjunction with providing parental guarantees on our behalf.

Private Placement

In February 2011, in connection with our Southern Pines Acquisition, we completed a private placement of approximately 17.4 million common units to various third-party investors for net proceeds of approximately $370 million, and the sale of approximately 10.2 million common units to PAA for net proceeds of approximately $230 million, including PAA s proportionate 2% general partner contribution of $12 million.

Intercompany Notes with PAA

In September 2009, we entered into a related party note payable to PAA with a fixed interest rate of 6.5%. In May 2010, we used the net proceeds from our initial public offering, together with borrowings under our credit facility, to repay approximately $468.4 million of the intercompany note. The remaining balance of $16.4 million was extinguished and treated as a capital contribution and part of PAA s investment in us.

In February 2011, in connection with our Southern Pines Acquisition, PAA provided debt financing to us in the form of a $200 million three-year senior unsecured loan that bears interest at 5.25%.

Contracts with Affiliates

In December 2008, PAA advanced $600,000 to Dean Liollio, President of our general partner, to assist him with the payment of relocation expenses incurred in connection with his employment. The advance, which did not bear any interest, was repaid in full prior to our IPO.

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Natural Gas Services Agreement and Related Transactions

In January and July of 2011, we sold a total of approximately 45 acres of land located in Acadia Parish, Louisiana to Plains Gas Solutions, LLC (PGS LLC , formerly known as CDM Max, LLC), a subsidiary of PAA, to be used for the development of a natural gas processing plant. The aggregate sales price of approximately $109,000 was based on a third party appraisal and the sale was made on an as is, where is basis without any representations or warranties by us. Effective July 1, 2011, we also entered into a Facilities Interconnect Agreement, Natural Gas Services Agreement, and Assignment and Bill of Sale with PGS LLC. Pursuant to these agreements, (i) our Pine Prairie subsidiary and PGS LLC agreed upon the terms pursuant to which PGS LLC would be allowed to connect its natural gas processing facility to Pine Prairie s header system, including the agreement by Pine Prairie to reimburse PGS LLC for approximately $1.5 million of capital costs associated with construction of certain of such interconnect facilities, (ii) PGS LLC agreed to provide certain gas handling services to our Pine Prairie facility and pay a fixed $125,000 per month access fee in exchange for the right to process any volumes delivered to its facility by Pine Prairie and retain for its own account any liquefiable hydrocarbons extracted therefrom, and (iii) we sold two inactive and unused pipeline segments located near PGS LLC s facility to PGS LLC in exchange for nominal consideration and without warranties of any kind. The Natural Gas Services Agreement has an initial term of ten years and is subject to annual renewals thereafter.

Natural Gas Sales

During 2011, we recognized approximately $2.3 million of revenues from sales of natural gas to PGS LLC.

Review, Approval or Ratification of Transactions with Related Persons

We have adopted policies for the review, approval and ratification of transactions with related persons similar to those that have been adopted by PAA. Pursuant to our Governance Guidelines, a director is 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.

Pursuant to our Code of Business Conduct, any executive officer must 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, our practice is to obtain approval of the board for the transaction. 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 require unanimous approval.

Item 14. ***Principal Accountant Fees and Services***

The following table details the aggregate fees billed directly to us for professional services rendered by our independent auditor (in millions):

	Year Ended December 31, 2011	Year Ended December 31, 2010
Audit fees [1]	$ 0.7	$ 0.5
Audit -related fees		
Tax fees [2]	0.3	0.1
All other fees		
Total	$ 1.0	$ 0.6

(1) Audit fees primarily relate to our annual audit (including internal control evaluation and reporting) and work performed on securities registration and other filings with the Securities and Exchange Commission.

(2) Tax fees primarily consist of those associated with tax processing as well as the preparation of Forms K-1 for our unitholders.

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Pre-Approval Policy

All services provided by our independent auditor are subject to pre-approval by our audit committee. The audit committee has instituted a policy that describes certain pre-approved non-audit services. We believe that the description of services is designed to be sufficiently detailed as to particular services provided, such that (i) management is not required to exercise judgment as to whether a proposed service fits within the description and (ii) the audit committee knows what services it is being asked to pre-approve. The audit committee is informed of each engagement of the independent auditor to provide services under the policy. All services provided by our independent auditor during the year ended December 31, 2011 were approved in advance by our audit committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) (1) *Financial Statements*

See Index to the Consolidated Financial Statements set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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SIGNATURES

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

PAA NATURAL GAS STORAGE, L.P.

By: PNGS GP LLC, its general partner

Date: February 28, 2012	By:	/s/ Greg L. Armstrong
	Name:	Greg L. Armstrong
	Title:	Chairman and Chief Executive Officer (Principal Executive Officer)
Date: February 28, 2012	By:	/s/ Dean Liollio
	Name:	Dean Liollio
	Title:	President
Date: February 28, 2012	By:	/s/ Al Swanson
	Name:	Al Swanson
	Title:	Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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

Name	Title	Date
/s/ Greg L. Armstrong Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of PNGS GP LLC (Principal Executive Officer)	February 28, 2012
/s/ Dean Liollio Dean Liollio	President and Director of PNGS GP LLC	February 28, 2012
/s/ Al Swanson Al Swanson	Executive Vice President, Chief Financial Officer and Director of PNGS GP LLC (Principal Financial Officer)	February 28, 2012
/s/ Donald C. O Shea Donald C. O Shea	Controller and Chief Accounting Officer of PNGS GP LLC (Principal Accounting Officer)	February 28, 2012
/s/ Harry N. Pefanis Harry N. Pefanis	Vice Chairman and Director of PNGS GP LLC	February 28, 2012
/s/ Victor Burk Victor Burk	Director of PNGS GP LLC	February 28, 2012
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director of PNGS GP LLC	February 28, 2012
/s/ Arthur L. Smith Arthur L. Smith	Director of PNGS GP LLC	February 28, 2012

PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

INDEX TO FINANCIAL STATEMENTS

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

PAA Natural Gas Storage, L.P. s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to evaluate the effectiveness of the Partnership s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership s internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of the Partnership s internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ GREG L. ARMSTRONG
Greg L. Armstrong

Chairman of the Board, Chief Executive Officer and

Director of PNGS GP LLC

(Principal Executive Officer)

/s/ AL SWANSON
Al Swanson

Executive Vice President and Chief Financial Officer of PNGS GP LLC

(Principal Financial Officer)

February 28, 2012

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Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of

PAA Natural Gas Storage, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, and of changes in partners capital and members capital, present fairly, in all material respects, the financial position of PAA Natural Gas Storage, L.P. at December 31, 2011 and 2010, and the results of its operations and its cash flows for the years ended December 31, 2011 and 2010, the period of September 3, 2009 to December 31, 2009, and the period of January 1, 2009 to September 2, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership s internal control over financial reporting based on our audit, which was an integrated audit in 2011 and 2010. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2012

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit amounts)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 496	$ 346
Restricted cash		20,000
Accounts receivable	33,600	12,786
Natural gas inventory	50,942	57
Other current assets	8,917	2,687
Total current assets	93,955	35,876
Property and equipment		
Property and equipment	1,311,553	892,645
Less: Accumulated depreciation, depletion and amortization	(31,140)	(14,837)
Property and equipment, net	1,280,413	877,808
Other assets		
Base gas	48,432	37,498
Goodwill	325,470	24,966
Intangibles and other assets, net	101,729	22,580
Total other assets, net	475,631	85,044
Total assets	$ 1,849,999	$ 998,728
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 40,884	$ 14,006
Short-term debt	67,992	
Accrued taxes	1,296	1,009
Total current liabilities	110,172	15,015
Long-term liabilities		
Note payable to PAA	200,000	
Long-term debt under credit agreements	253,508	259,900
Other long-term liabilities	693	423
Total long-term liabilities	454,201	260,323
Total liabilities	564,373	275,338
Commitments and contingencies (Note 13)		
Partners capital		
Common unitholders (59,193,825 units issued and outstanding at December 31, 2011)	1,037,161	474,489
Subordinated unitholders (25,434,351 units issued and outstanding at December 31, 2011)	230,359	236,853
General partner	28,156	13,637

Accumulated other comprehensive loss	(10,050)	(1,589)
Total partners capital	1,285,626	723,390
Total liabilities and partners capital	$ 1,849,999	$ 998,728

The accompanying notes are an integral part of these consolidated financial statements.

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Successor			Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010 (See Note 1)	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009 (See Note 1)
Revenues				
Firm storage services	$ 136,181	$ 90,965	$ 23,972	$ 42,649
Hub services	9,806	6,190	1,637	2,988
Natural gas sales	193,031			
Other	3,946	3,132	(358)	1,292
Total revenues	342,964	100,287	25,251	46,929
Costs and expenses				
Storage related costs	21,684	23,465	7,003	8,792
Natural gas sales costs	183,408			
Other operating costs (except those shown below)	11,621	7,242	3,257	4,820
Fuel expense	4,924	2,368	578	1,816
General and administrative expenses	22,566	15,965	4,083	3,562
Depreciation, depletion and amortization	33,714	14,119	3,578	8,054
Total costs and expenses	277,917	63,159	18,499	27,044
Operating income	65,047	37,128	6,752	19,885
Other income/(expense)				
Interest expense, net of capitalized interest	(5,354)	(7,323)	(4,262)	(4,352)
Other income/(expense)	5	(18)	(2)	(15)
Net income	$ 59,698	$ 29,787	$ 2,488	$ 15,518
Calculation of Limited Partner Interest in Net Income: (1)				
Net income	$ 59,698	$ 24,359	n/a	n/a
Less general partner interest in net income	1,793	537	n/a	n/a
Limited partner interest in net income	$ 57,905	$ 23,822	n/a	n/a
Net income per limited partner unit (1)				
Common and Series A subordinated units (2) (Basic)	$ 0.85	$ 0.54	n/a	n/a
Common and Series A subordinated units (2) (Diluted)	$ 0.85	$ 0.54	n/a	n/a
Weighted average limited partner units outstanding (1)				
Common and Series A subordinated units (2) (Basic)	68,250	44,375	n/a	n/a
Common and Series A subordinated units (2) (Diluted)	68,267	44,383	n/a	n/a

(1) Reflective of general and limited partner interest in net income since closing of the Partnership s initial public offering. See Note 4, Net Income per Limited Partner Unit.

(2) Excludes Series B subordinated units. See Note 4, Net Income per Limited Partner Unit.

The accompanying notes are an integral part of these consolidated financial statements.

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS CAPITAL AND MEMBERS CAPITAL

(in thousands)

	Members Capital	Partners Capital Limited Partners Common	Subordinated Series A	Subordinated Series B	General Partner	Accumulated Other Comprehensive Income/(Loss)	Total
Predecessor							
Balance at December 31, 2008	$ 380,301	$	$	$	$	$ (17,071)	$ 363,230
Net income	15,518						15,518
Contributions from members	8,500						8,500
Distributions to members	(8,500)						(8,500)
Net derivative gain/loss on cash flow hedges						1,990	1,990
Balance at September 2, 2009	$ 395,819	$	$	$	$	$ (15,081)	$ 380,738
Successor							
Balance at September 2, 2009	$ 395,819	$	$	$	$	$ (15,081)	$ 380,738
Net income	2,488						2,488
Net effect of pushdown accounting	34,437					15,081	49,518
Balance at December 31, 2009	$ 432,744	$	$	$	$	$	$ 432,744
Net income prior to closing of initial public offering	5,428						5,428
Extinguishment of related party note payable to PAA	16,375						16,375
Contribution of net assets to PAA Natural Gas Storage, L.P.	(454,547)	205,422	158,088	78,888	12,149		
Issuance of common units to public, net of offering and other costs		268,168					268,168
Modification of subordinated units			(22,903)	22,903			
Equity compensation expense		369			1,446		1,815
Modification of LTIP awards		912					912
Net income subsequent to closing of initial public offering		16,971	6,851		537		24,359
Distributions to unitholders		(17,337)	(6,974)		(496)		(24,807)
Distribution equivalent right payments		(16)					(16)
Contribution from general partner					1		1
Net deferred loss on cash flow hedges						(1,589)	(1,589)
Balance at December 31, 2010	$	$ 474,489	$ 135,062	$ 101,791	$ 13,637	$ (1,589)	$ 723,390
Net income		47,780	10,125		1,793		59,698
Issuance of common units to public, net of offering and other costs		587,342			12,000		599,342
Equity compensation expense		510			2,988		3,498
Distributions to unitholders and general partner		(72,897)	(16,619)		(2,266)		(91,782)
Distribution equivalent right payments		(63)					(63)

Contribution from general partner					4		4
Net deferred loss on cash flow hedges						(8,461)	(8,461)
Balance at December 31, 2011	$	$ 1,037,161	$ 128,568	$ 101,791	$ 28,156	$ (10,050)	$ 1,285,626

The accompanying notes are an integral part of these consolidated financial statements.

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Successor			Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010 (See Note 1)	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009 (See Note 1)
Cash flows from operating activities				
Net income	$ 59,698	$ 29,787	$ 2,488	$ 15,518
Adjustments to reconcile to cash flow from operations				
Depreciation, depletion and amortization	33,714	14,119	3,578	8,054
Gain on sale of base gas	(870)			
Equity compensation expense	4,174	2,747	1,467	304
Non-cash interest expense on borrowings from parent, net		5,081	4,262	
Unrealized gain on derivative instruments	(138)	(370)		
Change in assets and liabilities, net of acquisitions				
Accounts receivable and other assets	(17,214)	(5,264)	(480)	(2,166)
Natural gas inventory	(54,796)			
Accounts payable and accrued liabilities	19,326	(1,739)	3,950	893
Net cash provided by operating activities	43,894	44,361	15,265	22,603
Cash flows from investing activities				
Additions to property and equipment	(82,064)	(74,268)	(19,301)	(47,542)
Cash paid in connection with acquisition, net of cash acquired	(744,186)			
Decrease/(Increase) in restricted cash	20,000	(20,000)	14,000	(6)
Net cash paid for base gas	(4,259)	(9,488)	(4,366)	(11,193)
Other investing activities	235	176	11	180
Net cash used in investing activities	(810,274)	(103,580)	(9,656)	(58,561)
Cash flows from financing activities				
Borrowings under credit agreements	537,200	322,200		59,400
Repayments of borrowings under credit agreements	(475,600)	(62,300)		(29,900)
Repayments on term loan agreement			(25,213)	(1,225)
Borrowings from parent	200,000	24,000	2,400	
Repayment of borrowings from parent		(468,363)		
Net proceeds from issuance of common units	587,342	268,168		
Costs incurred in connection with financing arrangements	(2,571)	(2,441)		(4,639)
Contributions from general partner	12,004	1		
Distributions paid to unitholders	(89,516)	(24,311)		
Distributions paid to general partner	(2,266)	(496)		
Distribution equivalent right payments	(63)	(17)		
Contributions from members				8,500
Distributions to members				(8,500)
Net cash provided by/(used in) financing activities	766,530	56,441	(22,813)	23,636
Net increase/(decrease) in cash and cash equivalents	150	(2,778)	(17,204)	(12,322)

Cash and cash equivalents								
Beginning of period		346		3,124		20,328		32,650
End of period	$	496	$	346	$	3,124	$	20,328
Cash paid for interest, net of amounts capitalized	$	5,323	$	2,094	$		$	2,298
Cash paid for income taxes	$		$		$		$	795
Noncash Investing and Financing Activities								
Change in non-cash asset purchases included in accounts payable	$	(1,638)	$	(2,872)	$	1,008	$	1,534
Non-cash interest capitalized on borrowings from parent	$		$	5,130	$	5,362	$	

The accompanying notes are an integral part of these consolidated financial statements.

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PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Organization, Nature of Operations and Basis of Presentation

Organization, Nature of Operation, Basis of Consolidation and Presentation

PAA Natural Gas Storage, L.P. (the Partnership or PNG) is a Delaware limited partnership formed on January 15, 2010 to own the natural gas storage business of Plains All American Pipeline, L.P. (PAA). The Partnership is a fee-based, growth-oriented partnership engaged in the ownership, acquisition, development, operation and commercial management of natural gas storage facilities.

We currently own and operate three natural gas storage facilities located in Louisiana, Mississippi and Michigan. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Our Bluewater facility is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. As of December 31, 2011, through these facilities, PNG had a total of seven operational salt storage caverns and two depleted reservoirs used for natural gas storage, with an aggregate owned working gas storage capacity of approximately 76 billion cubic feet (Bcf). During the second half of 2010, we formed PNG Marketing, LLC as a commercial optimization company. PNG Marketing captures short-term market opportunities by utilizing a portion of our storage capacity and engaging in related commercial marketing activities.

On May 5, 2010, the Partnership completed its initial public offering (IPO) pursuant to which PAA sold an approximate 23.0% limited partner interest in the Partnership to the public. Immediately prior to the closing of the IPO, PAA and certain of its consolidated subsidiaries contributed 100.0% of the equity interests in PAA Natural Gas Storage, LLC (PNGS), the predecessor of the Partnership, and its subsidiaries to the Partnership. As of December 31, 2011, PAA owned approximately 64.1% of the equity interests in the Partnership, including our 2.0% general partner interest and limited partner interests consisting of 28,214,198 common units, 11,934,351 Series A subordinated units and 13,500,000 Series B subordinated units.

On September 3, 2009, PAA became the sole owner of PNGS by acquiring Vulcan Capital s 50.0% interest in PNGS (PAA Ownership Transaction) for an aggregate purchase price of $215.0 million. Although PNGS continued as the same legal entity after the PAA Ownership Transaction, all of its assets and liabilities were adjusted to fair value at the time of the transaction in accordance with push-down accounting requirements. The remeasurement of PNGS s assets and liabilities to fair value resulted in changes in carrying value for certain of PNGS s assets and liabilities. The changes in carrying value are summarized as follows (in thousands):

PP&E, net	$ 153,800
Base gas	(38,338)
Goodwill	(61,398)
Other long term assets	(4,546)
	$ 49,518

As a result of the push-down accounting requirements applied in conjunction with the PAA Ownership Transaction, the financial information of PNG for periods preceding (designated as Predecessor) and succeeding (designated as Successor) the PAA Ownership Transaction have been prepared under two different cost bases of accounting. Where applicable, a vertical line separates financial information for periods preceding and succeeding the PAA Ownership Transaction to highlight the fact that such information was prepared under different bases of accounting.

The accompanying consolidated financial statements include the accounts of PNG and its subsidiaries, all of which are wholly owned. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to the Partnership.

As used in this document, the terms we, us, our and similar terms refer to the Partnership and its subsidiaries, including its predecessors (when applicable), unless the context indicates otherwise.

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Note 2 Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amount of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to: (i) mark-to-market estimates of derivative instruments, (ii) accruals and contingent liabilities, (iii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iv) accruals related to incentive compensation, (v) valuation and recoverability of long-lived assets including property and equipment, intangible assets and goodwill, (vi) recognition of equity compensation plan expense and (vii) depreciation, depletion and amortization expense. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition - Gas Storage Services

We provide various types of natural gas storage services to customers. Revenues from these activities are classified as firm storage services or hub services.

Firm storage services consist of:

(i) *firm storage reservation fees* fixed monthly capacity reservation fees which are owed to us regardless of the actual storage capacity utilized by the customer. These fees are recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized; this also includes seasonal park and loan services, pursuant to which a customer will pay fees for the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis; and

(ii) *firm storage cycling fees and fuel-in-kind* fees for the use of injection and withdrawal services are based on the volume of natural gas nominated for injection and/or withdrawal; these fees are recognized in revenue in the period the volumes are nominated. We retain a small portion of the natural gas nominated for injection as compensation for our fuel use; the fuel-in-kind is reflected as revenue when received and in operating expense in the period the fuel is used in operations. Any excess fuel collected is carried as inventory at average cost.

Hub services consist of:

(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. These fees are recognized in revenue in the month that the services are provided.

Revenue Recognition - Natural Gas Sales

Revenues from the sale of natural gas by PNG Marketing are recognized at the time title to the gas sold transfers to the purchaser, which generally occurs upon delivery of the gas to the purchaser or its designee. Natural gas sales also includes applicable derivative gains and losses on commodity derivatives utilized by PNG Marketing in conjunction with natural gas sales activities. Any ineffectiveness on such derivatives designated as cash flow hedges, if any, is reflected as a component of other revenues in our consolidated statements of operations.

Revenue Recognition - Other Revenues

Other revenue includes revenues from the sale of crude oil and liquids produced in conjunction with the operation of our Bluewater facility, net of royalties and taxes and an access fee payable by Plains Gas Solutions, LLC (formerly known as CDM Max, LLC) (See Note 11). Additionally, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed as fuel for our facilities. Such revenue is recognized at the time title to the product sold transfers to the purchaser or its designee. Other revenue also includes unrealized and realized gains and losses associated with certain commodity derivatives which we have entered into which have not been eligible for hedge accounting.

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Storage Related Costs

Storage related costs consist of: (i) fees incurred to lease third party storage capacity and pipeline transportation capacity; and (ii) costs associated with certain loan services (see Base Gas). These costs are incurred to increase our operational flexibility and enhance the services we offer our customers.

Natural Gas Sales Costs

Natural gas sales costs include (i) the cost of natural gas, (ii) fees incurred for third-party transportation of gas acquired and sold and (iii) brokerage fees and commissions. Such costs are generally recognized at the time natural gas is sold by PNG Marketing. Natural gas sales costs also includes a portion of interest expense attributable to our hedged inventory (See Note 5). Natural gas sales costs for the year ended December 31, 2011 includes approximately $0.2 million of interest expense.

Other Operating Costs and General and Administrative Expenses

Other operating costs consist of various field operating expenses, including power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for field personnel, maintenance and integrity management costs, regulatory compliance, insurance and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity compensation expense), costs allocated to us from PAA, legal costs, acquisition related costs, contract and consultant costs and audit and tax fees.

Income and Other Taxes

No provision for U.S. federal income taxes related to our operations is included in our consolidated financial statements as we are treated as a partnership not subject to federal income tax and the tax effect of our activities accrues to our members. Income tax expense shown on our consolidated statement of operations for applicable predecessor periods is related to tax obligations of our predecessor. Other income/(expense) for the period from January 1 through September 2, 2009 includes approximately $0.5 million of income tax expense. As a result of PAA obtaining control over us in conjunction with the PAA Ownership Transaction, we report income taxes on a consolidated basis with PAA and are allocated our share of applicable tax obligations. Such amounts were not material for any periods subsequent to the PAA Ownership Transaction.

At December 31, 2011 and 2010 we had an income tax refund receivable of approximately $0.8 million that is attributable to periods prior to the PAA Ownership Transaction.

At December 31, 2011 and 2010, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing each class of limited partners interest in net income by the weighted average number of limited partner units for such class outstanding during the period. Pursuant to FASB guidance, the limited partners interest in net income is calculated by first reducing net income by the distribution pertaining to the current period s net income (including the incentive distribution right in excess of the 2.0% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partner interests in accordance with the contractual terms of the partnership agreement. Diluted earnings per limited partner unit, where applicable, reflects the potential dilution that could occur if securities or other agreements to issue additional units of a limited partner class, such as phantom unit awards, were exercised, settled or converted into such units.

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Cash and Cash Equivalents and Restricted Cash

Cash, restricted cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. At December 31, 2011, cash and cash equivalents are concentrated in a single financial institution and at times may exceed federally insured limits. We periodically assess the financial condition of the financial institution and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2011 and 2010, accounts payable included approximately $2.2 million and $0.4 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents to accounts payable and accrued liabilities. As of December 31, 2010, restricted cash consists of a $20 million deposit held in escrow in conjunction with the acquisition discussed in Note 3.

Accounts Receivable and Allowance for Doubtful Accounts

Our accounts receivable are from a broad mix of customers, including local gas distribution companies, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. We have a rigorous credit review process and closely monitor the potential credit risks associated with these counterparties in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit or parental guarantees. Purchases and sales of natural gas by PNG Marketing are subject to netting provisions (contractual terms that allow us and the counterparty to offset receivables and payables) which serve to mitigate credit risk.

We establish provisions for losses on accounts receivable if we determine that we will not collect all or part of an outstanding receivable balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. As of December 31, 2011 and 2010, substantially all of our accounts receivable were current and we had no allowance for doubtful accounts. We have not had any material accounts receivable write-offs since our inception.

Inventory

Natural gas inventory is valued at the lower of cost or market, with cost determined using an average cost method within specified inventory pools. As of December 31, 2011, PNG owned approximately 16.2 Bcf of natural gas inventory with a carrying value of approximately $50.9 million. Our natural gas inventory balance at December 31, 2011 reflects a lower of cost or market adjustment of approximately $6.0 million. The recognition of this adjustment, a component of natural gas sales costs in our accompanying consolidated statements of operations, was offset by the recognition of approximately $6.0 million of unrealized gains on derivative instruments (see Note 7) being utilized to hedge the future sales of our natural gas inventory. Accounts payable and accrued liabilities includes approximately $16.1 million due to counterparties for natural gas purchases as of December 31, 2011.

Gas Imbalances

We value gas imbalances due to or from interconnecting pipelines at market price as of the balance sheet date. Gas imbalances represent the difference between customer nominations and actual gas receipts from and gas deliveries to our interconnecting pipelines under various operational balancing agreements. As the settlements of imbalances are in-kind, changes in the balances do not typically have an impact on our earnings or cash flows. Gas imbalances are reflected as components of other currents assets and accounts payable and accrued liabilities on our consolidated balance sheets.

Property and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. In addition, we capitalize expenditures made for the purpose of maintaining or replacing the operating capacity, service capability and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day-to-day operation of our existing assets are charged to expense as incurred.

In conjunction with the development and expansion of our natural gas storage facilities, we capitalize direct costs associated with the development and construction projects. We also capitalize interest associated with projects that have not yet been placed into service. Capitalized interest was $10.9 million for the year ended December 31, 2011, $7.6 million for the year ended December 31, 2010 and $5.4 million and $10.2 million for the periods September 3, 2009 through December 31, 2009 and January 1, 2009 through September 2, 2009, respectively.

Base Gas

Base gas volumes at December 31, 2011 and 2010 consisted of 14.1 Bcf and 11.2 Bcf of natural gas in our storage facilities, respectively, which is necessary to operate the facility. Base gas is carried at historical cost with the exception of 5.0 Bcf that was recorded at fair value as of September 2, 2009 in conjunction with the PAA Ownership Transaction and approximately 2.2 Bcf of native natural gas within depleted reservoirs that is ascribed zero value due to uncertainty regarding our ability to ultimately recover such gas. The level of necessary base gas fluctuates based on the utilization of the caverns and reservoirs. At times, dependent on market conditions and utilization of the facilities, base gas may be loaned to customers. We classify amounts outstanding under base gas loans as a component of base gas in the accompanying consolidated financial statements. This gas will continue to be utilized as base gas, a long-term asset, upon settlement of the loan. As of December 31, 2011, we had outstanding loan agreements totaling approximately 12 Bcf of natural gas, substantially all of which is scheduled to be returned to us in the first half of 2012 in accordance with the terms of the agreements.

Approximately 3.0 Bcf of natural gas inventory acquired in conjunction with the Southern Pines Acquisition (See Note 3), with an acquired fair value of approximately $11.9 million, was sold (for no material gain or loss) after the acquisition to facilitate certain cavern development efforts. Upon completion of these activities, we purchased a similar volume of natural gas for approximately $13.6 million (including approximately $2.9 million related to derivative settlements) and designated this gas as base gas at Southern Pines.

During the year ended December 31, 2011, we sold approximately 2.0 Bcf of base gas for approximately $8.9 million and recognized total gains of approximately $0.9 million on these sales. Approximately $4.3 million of proceeds from a sale which occurred in December 2011 was not collected until January 2012. Also during 2011, we purchased approximately 1.2 Bcf of base gas for approximately $7.1 million (including approximately $1.8 million related to derivative settlements).

Net cash paid for base gas of approximately $4.3 million reflected on our consolidated statement of cash flows for the year ended December 31, 2011 consists of cash paid in conjunction with base gas purchases of approximately $8.9 million less cash received from base gas sales of approximately $4.6 million.

Asset Retirement Obligations

Financial Accounting Standards Board (FASB) guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets have contractual or regulatory obligations to perform remediation when the assets are abandoned. These assets, with regular maintenance, will continue to be in service for many years to come. It is not possible to predict when demands for our services will cease and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligation. We will record an asset retirement obligation in the period in which sufficient information becomes available for us to reasonably determine the settlement date.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance over the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. 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 , abandoning or 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.

There were no impairments of long-lived assets in the 2011, 2010 or 2009 periods.

Goodwill and Other Intangible Assets

We test goodwill at least annually and on an interim basis if a triggering event occurs to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by management. Our reporting units are our operating segments. Our operating segments are our Bluewater facility, our Pine Prairie facility and our Southern Pines facility (see Note 17). It is a two step process to test goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill. When the fair value is greater than book value, then the reporting unit s goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit s goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value. In conjunction with the PAA Ownership Transaction, we revalued all of our assets and liabilities to fair value, resulting in an adjusted goodwill balance of approximately $24.5 million at September 3, 2009. We test goodwill at least annually on June 30 of each year to determine if an impairment has occurred. There were no goodwill impairments during the 2011, 2010 and 2009 periods.

We amortize finite lived intangible assets over our best estimate of their useful life and in the periods that we estimate that the economic benefits of the intangible assets are realized. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. Intangible assets are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. Other than the customer contracts which were acquired in conjunction with the Southern Pines Acquisition (see Note 3) intangible assets are generally amortized on a straight-line basis.

Derivative Instruments and Hedging Activities

We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value pursuant to FASB guidance. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met. For derivative instruments designated as cash flow hedges, the effective portion of the change in fair value is deferred in accumulated other comprehensive income/(loss) and reclassified into earnings when the underlying hedged transaction affects earnings. All of our derivatives that qualify for hedge accounting are designated as cash flow hedges. With the exception of cash settlements associated with derivatives utilized to hedge base gas purchases or capital expansion activities, which are reflected as investing cash flows, cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows. We have determined that all of our physical natural gas purchase and sale agreements qualify for the NPNS exclusion. See Note 7 for further discussion of derivatives.

Fair Value

Among other things, ASC 820 Fair Value Measurements and Disclosures requires enhanced disclosures about assets and liabilities carried at fair value. As defined in ASC 820, fair value is the price that would be received from selling an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. ASC 820 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). See Note 8 for further discussion.

Environmental Matters

We record environmental liabilities when environmental assessments and/or remediation efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with the completion of a feasibility study or our commitment to a formal plan of action. Management is not aware of any association with any known material environmental liabilities as of December 31, 2011.

Recent Accounting Pronouncements

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for impairment tests performed during fiscal years (and interim periods within those years) that begin after December 15, 2010. We adopted this guidance on January 1, 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period

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pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. We adopted this guidance on January 1, 2011. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. The fair value hierarchy consists of designation to one of three levels based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires a gross presentation of activities within the level 3 rollforward. This guidance was effective for annual and interim reporting periods beginning after December 15, 2010. We adopted this guidance on January 1, 2011. See Note 8 for additional disclosure. Our adoption did not have a material impact on our financial position, results of operations, or cash flows.

Accounting Pronouncements Not Yet Effective

In December 2011, the FASB issued an accounting standard update that will require disclosure of information to help reconcile differences in the offsetting requirements for assets and liabilities under U.S. GAAP and IFRS. Under this new guidance, entities are required to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position, as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting agreements or similar arrangements. Entities will need to provide the following enhanced disclosures for both assets and liabilities within the scope of the new standard: (i) the gross amounts of those recognized assets and those recognized liabilities; (ii) the amounts offset to determine the net amounts presented in the statement of financial position; (iii) the net amounts presented in the statement of financial position; (iv) the amounts subject to an enforceable master netting arrangement or similar agreement not otherwise included in (ii); and (v) the net amount after deducting the amounts in (iv) from the amounts in (iii). The standard affects all entities with balances presented on a net basis in the financial statements, derivative assets and derivative liabilities, repurchase agreements, and financial assets and financial liabilities executed under a master netting or similar arrangement. Accordingly, the adoption of this guidance is not expected to have a material impact on our financial position as this standard only impacts the presentation of such financial information. This guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods.

In September 2011, the FASB issued guidance to simplify the goodwill impairment test by permitting entities to perform a qualitative assessment to determine whether further impairment testing is necessary. If qualitative factors indicate that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, an entity need not perform the two-step goodwill impairment test. This guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011, with earlier adoption permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued new guidance regarding the presentation of comprehensive income. This guidance requires entities to present reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement in which the components of net income and components of other comprehensive income are presented. It also eliminates the current option under U.S. GAAP to present components of other comprehensive income within the statement of changes in stockholders equity. The components of comprehensive income will be required to be presented within either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance is effective for interim and annual periods beginning after December 15, 2011, with earlier adoption permitted. Since this issuance only impacts the presentation of such financial information, adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows. On December 23, 2011, the FASB issued guidance deferring the new requirement to present reclassifications of other comprehensive income on the face of the income statement. Companies will still be required to adopt the other requirements contained in the new accounting standard for the presentation of comprehensive income.

In May 2011, the FASB issued guidance to amend certain measurement and disclosure requirements related to fair value in an effort to improve consistency with international reporting standards. This guidance is effective prospectively for interim and annual reporting periods beginning after December 15, 2011. Early adoption is not permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

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Note 3 Acquisitions

On February 9, 2011, we completed the acquisition of SG Resources Mississippi, L.L.C., owner of the Southern Pines Energy Center natural gas storage facility (the Southern Pines Acquisition). The purchase price was approximately $765 million (approximately $750 million, net of cash and other working capital acquired).

The fair value of the assets and liabilities acquired in the Southern Pines Acquisition is preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired. Several factors contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired. Such factors include the strategic location of the Southern Pines facility, the limited alternative locations and the extended lead times required to develop and construct such facility, along with its operational flexibility, organic expansion capabilities and synergies anticipated to be obtained from combining Southern Pines with our existing asset base.

The preliminary purchase price allocation is as follows (in millions):

Description	Amount	Average Depreciable Life (in years)
Inventory	$ 14	n/a
Property and equipment	341	5 70
Base gas	3	n/a
Other working capital (including approximately $13 million of cash acquired)	14	n/a
Intangible assets	92	2 10
Goodwill	301	n/a
Total	$ 765	

Our purchase price allocation is preliminary pending completion of internal valuation procedures primarily related to the valuation of intangible assets and the various components of the property and equipment acquired. The preliminary allocation of fair value to intangible assets above is comprised of a tax abatement valued at approximately $15 million and contracts valued at approximately $77 million, which have lives ranging from 2 10 years. Amortization of customer contracts under the declining balance method of amortization was approximately $12.8 million during the year ended December 31, 2011 and is estimated to be approximately $14.2 million, $13.3 million, $11.0 million and $8.3 million for the years ending December 31, 2012, 2013, 2014 and 2015, respectively. Goodwill or indefinite lived intangible assets will not be subject to depreciation or amortization, but will be subject to periodic impairment testing and, if necessary, will be written down to fair value should circumstances warrant. We expect to finalize our purchase price allocation during the first quarter of 2012.

Also in connection with the Southern Pines Acquisition, the Partnership became the owner, with the ability to remarket in the future, and ultimate obligor of the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2009 and the $100,000,000 Mississippi Business Finance Corporation Gulf Opportunity Zone Industrial Development Revenue Bonds (SG Resources Mississippi, LLC Project), Series 2010 (collectively, the GO Bonds). These were originally issued to fund the expansion of the Southern Pines facility. We remarketed the GO Bonds in August 2011 (see Note 5).

In conjunction with the Southern Pines Acquisition, we arranged financing totaling approximately $800 million to fund the purchase price, closing costs and the first 18 months of expected expansion capital. The financing consisted of $200 million of borrowings under a promissory note from PAA (see Note 5) and approximately $600 million from the issuance of our common units (see Note 6).

During the year ended December 31, 2011, we incurred approximately $4.1 million of acquisition-related costs associated with the Southern Pines Acquisition. Such costs are reflected as a component of general and administrative expenses in our consolidated statements of operations.

In May 2011, we entered into an agreement with the former owners of SG Resources Mississippi, L.L.C. with respect to certain outstanding issues and purchase price adjustments as well as the distribution of the remaining 5% of the purchase price that was escrowed at closing (totaling $37.3 million). Pursuant to this agreement, we received approximately $10 million and the balance was remitted to the former owners. Funds received were used to fund anticipated facility development and other related costs identified subsequent to closing. Approximately $2.7 million of capital expenditures were incurred related to matters covered by the agreement through December 31, 2011. Remaining amounts, included as a component of accounts payable and accrued liabilities as of December 31, 2011, will be utilized to offset applicable cavern development expenditures as incurred. Any remaining amounts upon completion of applicable cavern development procedures will reduce goodwill. Additionally, as part of this agreement, the parties executed releases of any existing and future claims, subject to customary carve-outs.

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Pro Forma Results

Total revenues generated by our Southern Pines facility of approximately $43.3 million for the period from February 9, 2011 (date of acquisition) through December 31, 2011 are included in our consolidated statements of operations for the year ended December 31, 2011. Disclosure of the earnings of our Southern Pines facility since the acquisition date is not practicable as it is not being operated as a standalone subsidiary.

Selected unaudited pro forma results of operations for the years ended December 31, 2011 and 2010, assuming the Southern Pines Acquisition had occurred on January 1, 2010, are presented below (in thousands, except per unit amounts):

	2011	2010
Total revenues	$ 346,927	$ 137,821
Net income(1)	$ 65,002	$ 40,998
Limited partner interest in net income(2)	$ 63,103	$ 35,279
Net income per limited partner unit(3)		
Basic	$ 0.89	$ 0.49
Diluted	$ 0.89	$ 0.49

(1) Amount for the 2010 period includes approximately $4.1 million of acquisition costs associated with the Southern Pines Acquisition.

(2) Amount for the 2010 period represents portion of net income attributable to limited partner interests for the period subsequent to the closing of our initial public offering on May 5, 2010.

(3) Excludes Series B subordinated units. See Note 4, Net Income per Limited Partner Unit.

Note 4 Net Income Per Limited Partner Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the year ended December 31, 2011 and for the period from May 5, 2010 (the closing of our initial public offering) through December 31, 2010 (amounts in thousands, except per unit data):

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	Year Ended December 31, 2011	May 5, 2010 to December 31, 2010
Net income	$ 59,698	$ 24,359
Less: General partner s incentive distribution[1]	611	51
Less: General partner 2.0% ownership	1,182	486
Net income available to limited partners	$ 57,905	$ 23,822
Numerator for basic and diluted earnings per limited partner unit:		
Allocation of net income amongst limited partner interests:		
Net income allocable to common units	$ 47,780	$ 16,971
Net income allocable to Series A subordinated units	10,125	6,851
Net income allocable to Series B subordinated units [2]		
Net income available to limited partners	$ 57,905	$ 23,822
Denominator:		
Basic weighted average number of limited partner units outstanding: [2]		
Common units	56,316	31,586
Series A subordinated units	11,934	12,789
Series B subordinated units	13,500	12,645
Diluted weighted average number of limited partner units outstanding: [2][3][4]		
Common units	56,333	31,594
Series A subordinated units	11,934	12,789
Series B subordinated units	13,500	12,645
Basic and diluted net income per limited partner unit: [2][3][4]		
Common units	$ 0.85	$ 0.54
Series A subordinated units	$ 0.85	$ 0.54
Series B subordinated units	$	$

(1) Based on the amount of the distribution declared per common and Series A subordinated limited partner units related to earnings for the applicable periods, our general partner was not entitled to receive any incentive distributions prior to the fourth quarter of 2010.

(2) During all periods presented, our Series B subordinated units were not entitled to participate in our earnings, losses or distributions in accordance with the terms of our partnership agreement as necessary performance conditions have not been satisfied. As a result, no earnings were allocated to the Series B subordinated units in our determination of basic and diluted net income per limited partner unit for each of the periods presented.

(3) Substantially all of our LTIP awards (described in Note 12), which are equity classified awards, contain provisions whereby vesting occurs only upon the satisfaction of a performance condition. None of these performance conditions had been satisfied during any of the periods presented. As such, our outstanding LTIP awards did not have a material impact in our determination of diluted net income per limited partner unit during any of the periods presented.

(4) The conversion of (i) our Series A subordinated units to common units and (ii) our Series B subordinated units to Series A subordinated units or common units is subject to certain performance conditions. None of these performance conditions had been satisfied as of December 31, 2011 therefore, there is no dilutive impact of such units in our determination of diluted net income per limited partner unit for any of the periods presented.

Note 5 Debt

Credit Agreement

In August 2011, we entered into a new $450 million five-year senior unsecured credit agreement, which provides for (i) $250 million under a revolving credit facility, which may be increased at our option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the GO Zone Term Loans) pursuant to the purchase, at par, of the GO Bonds we acquired in conjunction with the Southern Pines Acquisition (see Note 3). The revolving credit facility expires in August 2016. The purchasers of the two GO Zone Term Loans have the right to put, at par, to PNG the GO Zone Term Loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. Borrowings under the revolving credit facility accrue interest, at our election, on either the Eurodollar

Rate or the Base Rate, in each case plus an applicable margin. The GO Zone Term Loans accrue interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed, which generally provides that interest on the outstanding principal amount of (i) the GO Bonds 2009 shall accrue at a rate per annum equal to 75% of the sum of (a) the one-month Eurodollar Rate, plus (b) an applicable margin and (ii) the GO Bonds 2010 shall accrue at a rate per annum equal to 67% of the sum of (a) the one-month Eurodollar Rate plus (b) an applicable margin. Fees on issued letters of credit accrue at the applicable margin for Eurodollar Rate Loans, and a commitment fee accrues at an applicable margin. The applicable margin used in connection with interest rates and fees is based on our consolidated leverage ratio (as defined in the agreement) at the applicable time. This new credit agreement replaced our $400 million, three year senior unsecured revolving credit facility that was scheduled to mature in May 2013.

Our new credit agreement contains covenants and events of default which are substantially consistent with those contained in our previous credit facility. Our new credit agreement restricts, among other things, our ability to 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. In addition, the credit agreement contains restrictive covenants, including those that restrict our ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of our assets or enter into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also requires that we maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement.

As of December 31, 2011, borrowings of approximately $321.5 million were outstanding under our new credit agreement, which includes approximately $121.5 million under the revolving credit facility. The weighted average interest rate on all borrowings outstanding under our new credit agreement as of December 31, 2011 was approximately 1.9% (including commitment fees). As of December 31, 2011, borrowings of approximately $68.0 million under our revolving credit facility are classified as short-term debt. We classify as short-term debt any borrowings under our revolving credit facility which have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of our funded hedged natural gas inventory.

Our revolving credit facility includes the ability to issue letters of credit. As of December 31, 2011, we had $3.0 million of outstanding letters of credit under our revolving credit facility.

As of December 31, 2011, we were in compliance with the covenants required by our new credit agreement.

At December 31, 2010, borrowings of approximately $260 million were outstanding under our previous revolving credit facility, which was entered into in April 2010, subject to consummation of our initial public offering. This facility was a three-year, $400.0 million senior unsecured revolving credit facility that was scheduled to mature in May 2013. This credit facility bore interest based on LIBOR plus an applicable margin (approximately 3.4% in the aggregate including commitment fee as of December 31, 2010) determined based on funded debt-to-EBITDA levels (as defined in the credit agreement).

Borrowings from PAA

On February 9, 2011, in connection with the Southern Pines Acquisition (see Note 3), the Partnership borrowed $200 million from PAA pursuant to a three-year promissory note bearing interest at an annual rate of 5.25% (the PAA Promissory Note). Interest on the PAA Promissory Note is paid semiannually on the last business day of June and December. Interest paid to PAA attributable to the PAA Promissory Note during the year ended December 31, 2011 was approximately $9.3 million.

Immediately prior to our initial public offering, approximately $484.8 million was outstanding on a related party note payable to PAA, which was entered into in conjunction with the PAA Ownership Transaction. The note accrued interest and was payable in kind, at a rate of 6.5%. As discussed in Note 6, net proceeds of our initial public offering, along with borrowings under the then outstanding credit facility, were used to repay approximately $468.4 million of the related party note. The remaining balance of approximately $16.4 million was extinguished and treated as a capital contribution by PAA as part of PAA s initial investment in the Partnership.

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Debt Issuance Costs and Capitalized Interest

In conjunction with the modification of our credit agreements in August 2011, we incurred approximately $2.4 million of debt issuance costs, which, together with the remaining unamortized debt issuance costs on our previous revolving credit facility, will be amortized over the term of our new credit agreement. Approximately $2.4 million of debt issuance costs were incurred during the year ended December 31, 2010 related to our previous credit facility. Additionally, we accelerated the recognition of approximately $0.1 million of debt issuance costs related to our previous credit facility attributable to certain lenders that did not participate in our new credit agreement.

Capitalized interest for the periods ended December 31, 2011, December 31, 2010, December 31, 2009 and September 2, 2009 was approximately $10.9 million, $7.6 million, $5.4 million and $10.2 million, respectively.

Note 6 Partners Capital and Distributions

Initial Public Offering

As discussed in Note 1, immediately prior to the closing of our initial public offering on May 5, 2010, PAA and its subsidiaries contributed 98.0% of the equity interests in PNGS to the Partnership in exchange for certain limited partner interests. In addition, PNGS GP LLC, the general partner of the Partnership and a subsidiary of PAA, contributed 2.0% of the equity interests in PNGS to the Partnership in exchange for a 2.0% general partner interest in the Partnership as well as all of our incentive distribution rights, which entitle our general partner to increasing percentages of the cash we distribute in excess of $0.3375 per quarter.

On May 5, 2010, the Partnership issued approximately 13.5 million common units to the public, which included approximately 1.8 million common units issued pursuant to the full exercise of the underwriters over-allotment option, through an underwritten initial public offering representing an approximate 23.0% limited partner interest in us. Upon closing of the initial public offering and after giving effect to the exercise of the underwriters over-allotment option, PAA and its subsidiaries retained an approximate 77.0% equity interest in the Partnership, consisting of approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2.0% general partner interest in us. Total proceeds of the initial public offering were approximately $289.8 million. After deducting underwriting discounts and commissions and direct offering expenses, net proceeds of the offering were approximately $268.2 million. Net proceeds of the offering, along with $200.0 million of borrowings under the Partnership s then outstanding $400.0 million senior unsecured revolving credit facility, were used to repay intercompany indebtedness owed to PAA. The remaining balance of the intercompany indebtedness owed to PAA of approximately $16.4 million was extinguished and treated as a capital contribution and part of PAA s initial investment in the Partnership.

Equity Issuances

On February 8, 2011, in connection with the Southern Pines Acquisition, we completed the sale in a private placement of approximately 17.4 million common units to third-party purchasers and approximately 10.2 million common units to PAA for total proceeds of approximately $600 million, including PAA s proportionate general partner contribution. As a result of this transaction, PAA s equity ownership in the Partnership was reduced from approximately 77% to approximately 64%. We entered into Registration Rights Agreements with the third-party purchasers providing them with certain rights relating to registration of the resale of the common units under the Securities Act. The registration of the resale of these units was completed in August 2011.

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Outstanding Units

From the closing of our initial public offering on May 5, 2010 through December 31, 2011, changes in our issued and outstanding common, Series A subordinated and Series B subordinated units were as follows:

		Subordinated		
	Common	**Series A**	**Series B**	**Total**
Balance, May 5, 2010				
Initial public offering	31,584,529	13,934,351	11,500,000	57,018,880
Modification of subordinated units		(2,000,000)	2,000,000	
Vesting of LTIP awards	1,876			1,876
Balance, December 31, 2010	**31,586,405**	**11,934,351**	**13,500,000**	**57,020,756**
Units issued in private placements	27,598,045			27,598,045
Vesting of LTIP awards	9,375			9,375
Balance, December 31, 2011	**59,193,825**	**11,934,351**	**13,500,000**	**84,628,176**

Modification of subordinated units

In August 2010, our general partner amended and restated the Amended and Restated Agreement of Limited Partnership of the Partnership (the Second Amended and Restated Agreement) to increase our distribution coverage and growth profile of our common and Series A subordinated units and improve our posture with respect to potential acquisitions. The Second Amended and Restated Agreement reduced the number of Series A subordinated units held by PAA by 2.0 million units and increased the number of Series B subordinated units held by PAA by an equivalent amount. The Second Amended and Restated Agreement also established two additional tranches of Series B subordinated units. We accounted for this transaction as an exchange between entities under common control and, accordingly, reclassified approximately $22.9 million (the book value of 2.0 million Series A subordinated units at the time of the transaction) from the Series A subordinated unit limited partner capital account to the Series B subordinated unit limited partner capital account in our accompanying consolidated statement of changes in partners capital and members capital.

Series A subordinated units

All of our Series A subordinated units are owned by PAA. 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 for the Series A subordinated units 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 (150.0% 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 (150.0% 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.

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

All of our Series B subordinated units are owned by PAA. 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.

In February 2012, certain conversion terms of the Series B subordinated units were modified (see Note 18 for further discussion). Prior to this modification, the terms for conversion of the Series B subordinated units into Series A subordinated units upon satisfaction of the following operational and financial conditions were as follows:

- 2,600,000 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;

- 2,833,333 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;

- 2,066,667 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;

- 3,000,000 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 48 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4275 per unit (representing an annualized distribution of $1.71 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 three bullets, and (c) we make a quarterly distribution of available cash of at least $0.4275 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

- 3,000,000 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 48 Bcf, (b) we generate distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.45 per unit (representing an annualized distribution of $1.80 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 four bullets, and (c) we make a quarterly distribution of available cash of at least $0.45 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.

Before giving effect to the Second Amended and Restated Agreement, there were 4,600,000, 3,833,333 and 3,066,667 Series B subordinated units included in first, second and third tranches of Series B subordinated units, respectively.

Our general partner will determine whether the in-service operational requirements 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.

Distributions

Our partnership agreement requires that, within 45 days subsequent to the end of each quarter, we will distribute 100% of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Available cash is generally defined as all cash and cash equivalents on hand at the end of the quarter less reserves established by the managing member for future requirements.

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, incentive distributions in increasing percentages, up to 48.0%, of the cash we distribute in excess of that amount as follows:

	Total Quarterly Distributions 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%

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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.

The following table details the distributions subsequent to our initial public offering (in millions, except per unit amounts):

		Distributions Paid					
		Common	Series A Subordinated	General Partner			Distributions per limited partner unit
Date Declared	Date Paid or To Be Paid	Units	Units	Incentive	2%	Total	
January 12, 2012 [(1)]	February 14, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
October 11, 2011	November 14, 2011	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
July 11, 2011	August 12, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
April 11, 2011	May 13, 2011	$ 20.4	$ 4.1	$ 0.1	$ 0.5	$ 25.1	$ 0.3450
January 12, 2011	February 14, 2011	$ 10.9	$ 4.1	$ 0.1	$ 0.3	$ 15.4	$ 0.3450
October 12, 2010	November 12, 2010	$ 10.7	$ 4.0	$	$ 0.3	$ 15.0	$ 0.3375
July 13, 2010	August 13, 2010 [(2)]	$ 6.7	$ 2.9	$	$ 0.2	$ 9.8	$ 0.2114

(1) Payable to unitholders of record on February 3, 2012, for the period October 1, 2011 through December 31, 2011.

(2) Amount represents a quarterly distribution of $0.3375 per unit prorated from the May 5, 2010 closing date of the IPO through June 30, 2010.

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Note 7 Derivative Instruments and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating. We use various derivative instruments to (i) manage our price exposure associated with anticipated purchases or sales of natural gas and (ii) manage our exposure to interest rate risk. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives for undertaking hedges. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows of hedged items.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. The material commodity-related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales In the normal course of our operations, we purchase and sell natural gas and sell crude oil produced at our Bluewater facility. We use various derivatives, including index swaps and basis swaps, to manage the associated risks and to optimize profits. As of December 31, 2011, net derivative positions related to these activities included:

A short swap position of approximately 14.6 Bcf through April 2012 related to anticipated sales of natural gas.

A long swap position of approximately 0.6 Bcf through April 2013 related to anticipated purchases of natural gas.

A short swap position of approximately 22,000 barrels through December 2012, which hedge a portion of our anticipated sales of crude oil produced at our Bluewater facility.

Base Gas Management Our gas storage facilities require minimum levels of base gas to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of December 31, 2011, we have a long swap position of approximately 3.0 Bcf through April 2013 related to anticipated base gas purchases.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the underlying benchmark interest rate associated with borrowings outstanding under our credit agreement. During June and August 2011, we entered into three interest rate swaps to fix the interest rate on a portion of our outstanding debt. The swaps have an aggregate notional amount of $100 million with an average fixed rate of 0.95%. Two of these swaps terminate in June 2014 and the remaining swap terminates in August 2014. These swaps are designated as cash flow hedges. As of December 31, 2011, accumulated other comprehensive income (AOCI) includes deferred losses of $0.4 million that relate to open interest rate derivatives that were designated for hedge accounting. The deferred loss related to these instruments will be recognized as a component of interest expense over the terms of the hedged debt instruments.

Summary of Financial Statement Impact

For derivatives that qualify as a cash flow hedge, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. Derivatives that do not qualify or were not designated for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting change in cash flows of the hedged items are recognized in earnings each period.

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A summary of the impact of our derivative activities recognized in earnings for the years ended December 31, 2011 and 2010 is as follows (in thousands):

	Year Ended December 31, 2011			Year Ended December 31, 2010		
Location of Gain/(Loss)	Derivatives in Hedging Relationships(1)(2)(4)	Derivatives not Designated as a Hedge(3)	Total	Derivatives in Hedging Relationships(1)(2)(4)	Derivatives not Designated as a Hedge (3)	Total
Commodity Derivatives						
Natural gas sales	$ 18,614	$ 148	$ 18,762	$	$	$
Natural gas sales costs	5,973		5,973			
Other Revenues	132	6	138	816	(435)	381
Interest Rate Derivatives						
Interest expense	(327)		(327)			
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 24,392	$ 154	$ 24,546	$ 816	$ (435)	$ 381

(1) Amounts reported as a component of Natural Gas Sales represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.
(2) Amounts reported as a component of Other Revenues include the ineffective portion of our cash flow hedges recognized in earnings.
(3) Amounts include realized and unrealized gains or losses for derivatives that did not qualify or were not designated for hedge accounting during the period.
(4) Amounts include unrealized gains of approximately $6.0 million reclassified from AOCI to earnings for the year ended December 31, 2011 to offset a lower of cost or market adjustment relating to the carrying value of our inventory.

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2011 (in thousands):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 31,541	Other current assets	$ (16,766)
	Other long-term assets	3,292	Other long-term assets	(1,896)
Interest rate derivatives			Other current liabilities	(236)
			Other long-term liabilities	(212)
Total derivatives designated as hedging instruments		$ 34,833		$ (19,110)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 138	Other current assets	$ (515)
	Other long-term assets	5		
Total derivatives not designated as hedging instruments		$ 143		$ (515)
Total Derivatives		$ 34,976		$ (19,625)

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (in thousands):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 43	Other current assets	$ (4)
Total derivatives designated as hedging instruments		$ 43		$ (4)

As of December 31, 2011, there was a net loss of $10.1 million deferred in AOCI. Amounts deferred in AOCI include amounts associated with settled derivatives for which the underlying anticipated hedge transactions are still probable of occurring. The deferred loss in AOCI is expected to be reclassified to future earnings contemporaneously with the earnings recognition of the underlying hedged transactions. Certain underlying hedged transactions are for base gas purchases or other capital expansion expenditures. As we account for base gas as a long-term asset, which is not subject to depreciation, amounts related to base gas will not be reclassified to future earnings until such gas is sold or in the event an impairment charge is recognized in the future. Amounts related to other capital expansion activities will be reclassified to future earnings over the estimated useful live of the applicable asset. Deferred losses of approximately $7.1 million (including $4.7 million associated with base gas purchases) are included in AOCI as of December 31, 2011. Remaining amounts in AOCI as of December 31, 2011 are associated with both open and settled derivative positions. Of the total net loss deferred in AOCI at December 31, 2011, we expect to reclassify a net loss of approximately $3.8 million to earnings in the next twelve months. Amounts deferred are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2011, we reclassified a gain of approximately $0.7 million from AOCI to natural gas sales when it was deemed probable the anticipated hedged transactions would not occur. During the year ended December 31, 2010, no amounts were reclassified from AOCI as a result of hedged transactions being deemed probable that the underlying hedged transaction would not occur.

Amounts recognized in AOCI for derivatives and amounts reclassified to earnings during the years ended December 31, 2011 and 2010 are as follows (in thousands):

	For the Years Ended December 31,	
	2011	2010
Commodity derivatives, net [(1)]	$ 16,574	$ (773)
Interest rate derivatives, net [(1)]	(775)	
Reclassification adjustments, net [(2)]	(24,260)	(816)
Total	$ (8,461)	$ (1,589)

(1) Amounts reflect net unrealized derivative gains and losses deferred in AOCI for the period. Negative amounts represent a net deferral of losses and positive amounts reflect a net deferral of gains on the applicable activity.

(2) Reclassification adjustments represent transfers of deferred gains and losses out of AOCI and into earnings for the period. Negative amounts represent the reclassification of previously deferred net gains into earnings and positive amounts represent the reclassification of previously deferred net losses into earnings for the period. Reclassification adjustments may include realization of amounts originally deferred to AOCI in both the current period as well as prior periods.

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Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our commodity derivatives, which are all exchange-traded or exchange-cleared, are transacted through a brokerage account and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of December 31, 2011, we had a net broker payable of approximately $8.6 million (consisting of initial margin of $5.7 million decreased by $14.3 million of variation margin returned to us). Our interest rate derivatives, which are over-the-counter instruments, do not have margin requirements. At December 31, 2011 and 2010, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

Note 8 Fair Value Measurements

Derivative Financial Assets and Liabilities

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2011 (in thousands)				Fair Value as of December 31, 2010 (in thousands)			
Recurring Fair Value Measures [1]	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 15,799	$	$	$ 15,799	$ 39	$	$	$ 39
Interest rate derivatives		(448)		(448)				
Total	$ 15,799	$ (448)	$	$ 15,351	$ 39	$	$	$ 39

(1) Derivative assets and (liabilities) are presented above on a net basis but do not include any related cash margin deposits.

The determination of the fair values above includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives and interest-rate derivatives includes adjustments for credit risk. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are exchange-traded commodity derivatives such as futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy are interest rate derivatives that are traded in active markets. The fair value of these derivatives is based on broker or dealer price quotations which are corroborated with market observable inputs, including forward interest rates obtained from pricing services.

Level 3

Level 3 of the fair value hierarchy consists of derivatives based on unobservable inputs. As of December 31, 2011 and 2010, we did not have any level 3 derivatives.

Other Financial Instruments

For certain of the Partnership s other financial instruments, including cash and cash equivalents, restricted cash, accounts receivable, and accounts payable, the carrying amounts approximate fair value due to their short maturities. With respect to the Partnership s outstanding borrowings under our note payable to PAA and our $450 million senior unsecured credit agreement, the carrying amounts of these obligations approximate fair value due to the short maturity of both obligations and the variable interest rate terms set forth under our credit agreement.

Note 9 Comprehensive Income

Comprehensive income includes net income and all other non-owner changes in equity. Components of comprehensive income (loss) are presented below (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010 (See Note 1)	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009 (See Note 1)
Net income	$ 59,698	$ 29,787	$ 2,488	$ 15,518
Net derivative gain/(loss) on cash flow hedges	(8,461)	(1,589)		1,990
Total comprehensive income	$ 51,237	$ 28,198	$ 2,488	$ 17,508

Note 10 Major Customers and Concentration of Credit Risk

Approximately 17% of our total revenues for the year ended December 31, 2011 were generated from physical sales of natural gas executed through Natural Gas Exchange Inc., a commodity exchange. No other customer accounted for greater than 10% of our total revenues for the year ended December 31, 2011. During the year ended December 31, 2010, Iberdrola Renewables, Inc., accounted for approximately 13% of our storage revenues. During the period from September 3, 2009 to December 31, 2009, Anadarko Energy Services, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 10%, 16% and 12% of our storage revenues, respectively. During the period from January 1, 2009 to September 2, 2009, Iberdrola Renewables, Inc. and Guardian Pipeline, LLC accounted for approximately 17% and 13% of our storage revenues, respectively. This concentration in the volume of business transacted with a limited number of customers subjects us to risk.

Financial instruments that subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from customers that operate in the natural gas industry. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions, which subjects us to credit risk. We review credit exposure and financial information of our customers and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced.

Note 11 Related Party Transactions

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of Plains All American GP LLC (GP LLC), the general partner of Plains AAP, L.P. which is the sole member of PAA GP LLC, PAA s general partner. References to PAA, unless the context otherwise requires, include GP LLC. We reimburse PAA for all direct and indirect expenses it incurs or payments it makes on our behalf, including certain capital expansion costs, and all other expenses allocable to us or otherwise incurred by PAA in connection with the operation of our business. These expenses are recorded in general and administrative expenses and other operating costs on our income statement and include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf. We record these costs on the accrual basis in the period in which PAA s general partner incurs them. Our agreement with PAA provides that PAA will determine the expenses allocable to us in any reasonable manner determined by PAA in its sole discretion. The amount of the allocation increased after the PAA Ownership Transaction, as prior to September 2, 2009, the joint venture agreement with Vulcan Capital did not permit PAA to charge us for executive officer expenses and subsequent to the PAA Ownership Transaction PAA devoted a greater proportion of their resources to our operations. Instead, such items were compensated under a contingent management fee arrangement that was subject to achievement of performance benchmarks not considered probable. Such contingent management fee was addressed by the negotiation with Vulcan Capital and reflected in the total valuation. Total costs reimbursed by us to PAA for the periods ended December 31, 2011, December 31, 2010, December 31, 2009 and September 2, 2009, were approximately $15.2 million, $19.5 million, $3.6 million and $7.9 million, respectively. Of these amounts $3.6 million, $3.4 million, $1.1 million and $1.0 million, respectively, were allocated personnel costs for shared services and the remainder consisted of direct costs that PAA paid on our behalf along with our allocation of insurance premiums for participation in PAA s insurance programs. PAA, in conjunction with input from our general partner, estimates the percentage of time that each shared service department spends on items related to our operations and allocates this percentage of their personnel costs to us. Due to our general partner s close involvement in this process, we believe that the method used is reasonable.

As of December 31, 2011 and December 31, 2010, PNG had net amounts due to PAA and certain of its affiliates of approximately $0.6 million and $0.6 million, respectively, included in accounts payable and accrued liabilities on our accompanying consolidated balance sheets.

As of December 31, 2011 and December 31, 2010, PNG s obligation for unvested equity-based compensation awards for which we are required to reimburse PAA upon vesting and settlement was approximately $1.2 million and $1.0 million, respectively. Approximately $0.7 million and $0.6 million of such amounts were reflected in accounts payable and accrued liabilities in our accompanying consolidated balance sheets as of December 31, 2011 and December 31, 2010, respectively, with the remaining balances included as a component of other long-term liabilities at each respective date.

As of December 31, 2011, outstanding parental guarantees issued by PAA to third parties on behalf of PNG Marketing were approximately $31 million. No amounts were due to PAA as of December 31, 2011 under such guarantees and no payments were made to PAA under such guarantees during the year ended December 31, 2011. We pay PAA a quarterly fee in exchange for providing such parental guarantees. The quarterly fee, which is based on actual usage, is subject to a quarterly minimum of $12,500 regardless of utilization to cover PAA s administrative costs. During the year ended December 31, 2011, we incurred approximately $0.1 million of expense under our obligation to reimburse PAA for administrative costs incurred in conjunction with providing parental guarantees on our behalf.

Omnibus Agreement

In conjunction with our initial public offering in May 2010, we entered into an omnibus agreement with PAA and certain of its affiliates, pursuant to which we agreed upon certain aspects of our relationship with them, including, among other things (1) 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, (2) the provision by PAA s general partner of such personnel 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 personnel, (3) certain indemnification obligations, and (4) our use of the name PAA and related marks. Under this agreement, PAA indemnifies us against certain environmental liabilities, tax matters, and title or permitting defects generally for a period of three years after the closing of our initial public offering. The environmental indemnifications are subject to a cap of $15.0 million and require us to pay the first $250 thousand of costs incurred. In addition, we have indemnified PAA against any losses, costs or damages incurred by PAA or its general partner that are attributable to the ownership and operation of our assets following the close of the initial public offering.

Tax Sharing Agreement

In conjunction with our initial public offering in May 2010, we entered into a tax sharing agreement with PAA, pursuant to which we and PAA agreed 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 May 5, 2010. Subsequent to the PAA Ownership Transaction, income tax expense allocated to us under applicable allocation methodologies has not been material.

Natural Gas Services Agreement and Related Transactions

In January and July of 2011, we sold a total of approximately 45 acres of land located in Acadia Parish, Louisiana to Plains Gas Solutions, LLC (PGS LLC , formerly known as CDM Max, LLC), a subsidiary of PAA, to be used for the development of a natural gas processing plant. The aggregate sales price of approximately $109,000 was based on a third party appraisal and the sale was made on an as is, where is basis without any representations or warranties by us. Effective July 1, 2011, we also entered into a Facilities Interconnect Agreement, Natural Gas Services Agreement, and Assignment and Bill of Sale with PGS LLC. Pursuant to these agreements, (i) our Pine Prairie subsidiary and PGS LLC agreed upon the terms pursuant to which PGS LLC would be allowed to connect its natural gas processing facility to Pine Prairie s header system,

including the agreement by Pine Prairie to reimburse PGS LLC for approximately $1.5 million of capital costs associated with construction of certain of such interconnect facilities, (ii) PGS LLC agreed to provide certain gas handling services to our Pine Prairie facility and pay a fixed $125,000 per month access fee in exchange for the right to process any volumes delivered to its facility by Pine Prairie and retain for its own account any liquefiable hydrocarbons extracted therefrom, and (iii) we sold two inactive and unused pipeline segments located near PGS LLC s facility to PGS LLC in exchange for nominal consideration and without warranties of any kind. The Natural Gas Services Agreement has an initial term of ten years and is subject to annual renewals thereafter.

Natural Gas Sales

During the year ended December 31, 2011, we recognized approximately $2.3 million of revenues from sales of natural gas to PGS LLC.

Relationship with our general partner

Except as previously disclosed, we are not party to any material transactions with our general partner or any of its affiliates. Additionally, our general partner is not obligated to provide any direct or indirect financial assistance to us or to increase or maintain its capital investment in us.

Note 12 Equity Compensation Plans

Long Term Incentive Plan (LTIP)

On April 27, 2010, PNGS GP LLC, the general partner of the Partnership, adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the 2010 LTIP Plan) for the employees, directors and consultants of our general partner and its affiliates, including PAA, who perform services on our behalf. Although other types of awards are contemplated under the 2010 LTIP Plan, currently outstanding awards are limited to phantom units, which mature into the right to receive common units of PNG, or the equivalent cash value, upon vesting. The 2010 LTIP Plan limits the number of common units that may be delivered pursuant to awards under the plan to 3,000,000 units.

During the second quarter of 2010, 658,500 phantom units were granted under the 2010 LTIP Plan to directors, officers and other employees, a portion of which were granted upon conversion of outstanding awards denominated in common units of PAA. Of this total, (i) 30,000 phantom units, issued to non-employee directors, will vest annually in 25.0% increments and have an automatic re-grant feature such that as they vest, an equivalent amount is granted; (ii) 326,000 phantom units, issued to members of management, were scheduled to vest in one-third increments upon the later of (a) the May 2012 distribution date and the date we pay a quarterly distribution of at least $0.3875, (b) the May 2013 distribution date and the date we pay a quarterly distribution of at least $0.4500, and (c) the May 2014 distribution date and the date we pay a quarterly distribution of at least $0.4750; and (iii) 302,500 phantom units, issued to members of management, were scheduled to vest in 25.0% increments in connection with the conversion of our Series A subordinated units and the conversion of each of the first three tranches of our Series B subordinated units. Distribution equivalent rights (DERs) were also awarded with respect to 342,500 of the phantom unit grants.

In November 2010, our Board of Directors approved the modification (subject to agreement by the individual award recipients) of 302,500 LTIP awards originally granted in the second quarter of 2010 to more closely align the vesting of these awards to the conversion of our Series B subordinated units as a result of the modification of our subordinated units in August 2010 (see Note 6). Such modifications provided that the awards would vest in 20% increments in connection with the conversion of our Series A subordinated units and the conversion of each of the first four tranches of our Series B subordinated units. The impact of this modification was not material.

Outstanding equity compensation awards granted to members of management were further modified in February 2012. See Note 18 for additional information.

Our LTIP activity for awards issued under the 2010 LTIP Plan is summarized in the following table (in thousands, except per unit data):

	Units	Weighted Average Grant Date Fair Value per Unit	
Outstanding, May 5, 2010			
Granted[(1)]	676	$	19.41
Vested	(2)	$	23.08
Cancelled or forfeited	(50)	$	19.22
Outstanding, December 31, 2010[(2)]	624	$	19.42
Granted[(3)]	24	$	22.06
Vested	(9)	$	23.31
Cancelled or forfeited	(140)	$	19.20
Outstanding, December 31, 2011[(4)]	499	$	19.53

(1) Includes 662,000 equity classified awards and 13,500 liability classified awards.
(2) Includes 610,000 equity classified awards and 13,500 liability classified awards.
(3) Includes 24,375 equity classified awards.
(4) Includes 490,000 equity classified awards and 8,500 liability classified awards.

Prior to our initial public offering and adoption of the 2010 LTIP Plan, certain of our officers and other individuals providing direct services on our behalf were granted LTIP awards under LTIP plans sponsored by PAA s general partner (PAA LTIP Awards). Such awards, which allow settlement in cash or PAA common units upon vesting at the election of PAA s general partner, generally contained performance conditions based on the attainment of certain annualized PAA distribution levels or the attainment of specific PNG EBITDA levels and vested upon the later of a certain date or the attainment of such levels. In connection with grants made in the second quarter of 2010 under the 2010 LTIP Plan, substantially all of the then outstanding liability-classified PAA LTIP awards held by PNG management were converted to equity-classified PNG LTIP awards, which resulted in a reclassification to partners capital of approximately $0.9 million of compensation expense recognized on such awards through the modification date. As of December 31, 2011, approximately 28,000 PAA LTIP awards are outstanding and unvested. We reimbursed PAA approximately $0.8 million, $1.1 million, $0.4 million and nil for PAA LTIP awards that vested during the periods that ended December 31, 2011, December 31, 2010, December 31, 2009 and September 2, 2009, respectively.

The fair value of our liability classified awards is calculated based on the closing price of the underlying PAA or PNG units as of each balance sheet date and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the service period that will not be received by the award recipients. The fair value of our equity classified awards is calculated based on the closing price of our common units as of the respective grant dates and adjusted for the present value of any distributions that are estimated to occur on the underlying units over the service period that will not be received by the award recipient. The fair value of these awards is recognized as compensation expense over the service period. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would be as if we had been accruing for these awards since the grant date. For liability classified awards, we recognize DER payments in the period the payment is earned as compensation expense. For equity classified awards, we recognize DER payments in the period the payment is made as a reduction of partners capital. DERs terminate with the vesting or forfeiture of the underlying LTIP award. Substantially all of our equity compensation expense is reflected as a component of general and administrative expenses in our accompanying consolidated statements of operations.

Our accrued liability at December 31, 2011 and 2010 related to all outstanding liability classified LTIP awards is approximately $1.2 million and $1.0 million, respectively. Approximately $0.7 million and $0.6 million of such amounts were reflected in accounts payable and accrued liabilities in our accompanying consolidated balance sheets as of December 31, 2011 and 2010, respectively, with the remaining balances included as a component of other long-term liabilities at each respective date. Compensation expense recognized on 2010 LTIP Plan awards reflects our assessment that, as of December 31, 2011, an annualized PNG distribution of $1.45 and the conversion of our Series A subordinated units are probable of occurring.

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Class B Awards of Our General Partner

In July 2010, the Board of Directors of our general partner authorized the issuance of 165,000 Class B Units (PNGS Class B Units) of PNGS GP LLC (PNG s general partner) in order to create long term incentives for our management. The entire economic burden of the PNGS Class B Units, which are equity classified, will be borne solely by our general partner and will not impact our cash or our units outstanding. We will recognize the grant date fair value of the PNGS Class B Units as compensation expense over the service period, with such expense recognized as a capital contribution. We will not be obligated to reimburse our general partner for such costs and any distributions made on the PNGS Class B Units will not reduce the amount of cash available for distribution to our unitholders.

As of December 31, 2011, 74,250 PNGS Class B Units were outstanding and the remaining units are reserved for future grants. The PNGS Class B Units earn the right to participate in distributions (i.e. become earned) in 25% increments 180 days following the payment by PNG of quarterly distributions that equate to annualized distribution levels of $2.00, $2.30, $2.50 and $2.70. When PNGS Class B Units become earned units, they will participate in quarterly distributions paid to our general partner in excess of $2.5 million. In addition, 50% of the applicable earned units vest immediately upon becoming earned units and the remaining 50% vest on the fifth anniversary of the date of grant. If PNGS Class B Units become earned units after the fifth anniversary of the date of grant, 100% of such units will vest immediately upon becoming earned units. Assuming all 165,000 PNGS Class B Units were granted and earned, the maximum participation rate would be 6% of PNG s quarterly general partner distribution in excess of $2.5 million. No expense was recognized during the twelve months ended December 31, 2011 or 2010 as it was not deemed probable that any of the performance conditions necessary for the PNGS Class B Units to become earned would be met.

Transaction/Transition Awards Granted by PAA

During September 2010, PAA entered into agreements with certain officers of PAA pursuant to which these individuals were granted approximately 375,000 awards denominated in PNG common units, Series A subordinated units, and Series B Subordinated units. The awards will vest upon the completion of the service period and certain performance conditions including the conversion of PNG s Series A subordinated units into common units of PNG and the conversion of PNG s Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by PAA. The entire economic burden of these agreements will be borne solely by PAA and will not impact our cash or our units outstanding. Since these individuals also serve as officers of PNG and PNG benefits as a result of the services they provide, we will recognize the grant date fair value of these awards as compensation expense over the service period, with such expense recognized as a capital contribution. During the years ended December 31, 2011 and 2010, we recognized approximately $2.7 million and $1.5 million, respectively, of expense and a corresponding capital contribution associated with these awards.

Other Consolidated Equity Compensation Information

The table below summarizes the expense recognized and the value of vested awards related to our equity compensation plans (in thousands):

	Successor						Predecessor	
	Year ended December 31, 2011		Year ended December 31, 2010		September 3, 2009 through December 31, 2009		January 1, 2009 through September 2, 2009	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense[(1)(2)(3)]	$ 676	$ 3,498	$ 932	$ 1,815	$ 1,467	$	$ 304	$
LTIP cash settled vestings	$ 711	$	$ 1,123	$	$ 383	$	$	$
LTIP unit settled vestings	$	$ 174	$	$ 46	$	$	$	$
Distribution equivalent right payments	$ 18	$ 63	$ 10	$ 16	$	$	$	$

(1) Includes expense associated with transaction awards granted by PAA and denominated in PNG units owned by PAA. These awards, which were granted in September 2010, are not included in units outstanding above. The entire economic burden of these agreements will be borne solely by PAA and will not impact our cash or units outstanding. Since these individuals also serve as officers of PNG and PNG benefits as a result of the services they

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provide, we recognize the grant date fair value of these awards as compensation expense over the service period, with such expense recognized as a capital contribution. We recognized approximately $2.7 million and $1.5 million of compensation expense associated with these awards during the years ended December 31, 2011 and 2010, respectively.

(2) Equity compensation expense for periods prior to our initial public offering relates to awards that were denominated in PAA units and were treated as liability-classified awards. Subsequent to our initial public offering, substantially all of the then outstanding PAA unit denominated awards were converted to equity-classified awards denominated in PNG units.

(3) Equity compensation expense for the years ended December 31, 2011 and 2010 includes approximately $3.5 million and $1.8 million, respectively, of expense associated with equity-classified awards, including approximately $2.7 million and $1.5 million, respectively, associated with the transaction awards.

Based on the December 31, 2011 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $3.8 million (which includes approximately $2.0 million associated with the awards granted by PAA which we do not bear the economic burden of) of additional expense over the estimated service period of our outstanding awards related to the remaining unrecognized fair value. For our liability classified awards, this estimate is based on the fair value of the outstanding awards as of December 31, 2011. For our equity classified awards, this estimate is based on the grant date fair value of such awards. Actual amounts may materially differ as a result of a change in the market price of our units and/or probability assessment regarding future distributions. We estimate that the remaining fair value of awards outstanding as of December 31, 2011 will be recognized in expense as shown below (in thousands):

Year	**Equity Compensation Plan Fair Value Amortization (1)(2)(3)**
2012	$ 860
2013	574
2014	220
2015 and thereafter	128
Total	**$ 1,782**

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2011.

(2) Amounts do not include fair value associated with awards which are not dilutive to our limited partners or impact cash flow available for distribution to our limited partners.

(3) Amounts do not reflect the impact of the February 2012 award modification discussed in Note 18.

Note 13 Commitments and Contingencies

In the ordinary course of doing business, we lease storage and transportation capacity from third parties and enter into purchase commitments in conjunction with our operations and our capital expansion program. As of December 31, 2011, we had 1.8 Bcf of storage capacity under lease from third parties and had secured the right to 356 MMcf per day of firm transportation service on various pipelines. In addition, we may enter into contracts related to construction costs associated with certain of our capital projects.

The following table includes our best estimate of the amount and timing of the payments due under our contractual obligations as of December 31, 2011 (in thousands):

	Total	2012	2013	2014	2015	2016	Thereafter
Storage and transportation agreements[(1)]	$ 25,103	$ 12,114	$ 6,547	$ 4,448	$ 1,994	$	$
Purchase obligations[(2)]	21,724	6,330	1,866	1,866	1,866	1,866	7,930
Leases[(3)]	354	134	29	29	29	29	104
Total	$ 47,181	$ 18,578	$ 8,442	$ 6,343	$ 3,889	$ 1,895	$ 8,034

(1) Includes third party storage and transportation agreements. Expense recognized related to these agreements for the years ended December 31, 2011 and 2010 and the periods from September 3 through December 31, 2009 and January 1, through September 2, 2009 was approximately $18.8 million, $17.7 million, $4.8 million and $7.2 million, respectively.

(2) Primarily includes amounts related to utility contracts and capital expansion activities.

(3) Includes operating leases as defined by FASB guidance.

Environmental

We may experience releases of crude oil, natural gas, brine or other contaminants into the environment, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may affect our business. As of December 31, 2011, we have not identified any material environmental obligations.

Litigation

We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Insurance

A natural gas storage facility, associated pipeline header system, and gas handling and compression facilities may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property, base gas, and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating natural gas storage facility, associated pipeline header system, and gas handling and compression facilities, including the potential loss of significant revenues. The overall trend in the insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

We participate in an insurance program managed by PAA. Due to recent increases in cost combined with stricter coverage limitations, we decided to not purchase hurricane or windstorm related property damage coverage for 2011/12 and we will self insure this risk. This decision does not affect our third party liability insurance coverage which, still covers hurricane related liability claims.

During the third quarter of 2011, we received $3.0 million of property insurance proceeds related to the January 2011 operational incident and fire at our Bluewater facility.

Pine Prairie Project Sale and Lease

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. (the Industrial Development Board) and leased back the property. 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 will not be 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 payments in lieu of ad valorem property taxes (PILOT Payments) beginning in 2010, calculated as the difference between $500,000 and a three year average of ad valorem inventory tax revenues applicable to natural gas in the facility for the prior three consecutive calendar years. During 2011 and 2010, we made PILOT Payments of approximately $37,000 and $192,000, respectively.

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.

The lease also contains certain covenants that Pine Prairie must comply with in order to obtain the related ad valorem property tax benefits during the term of the lease including maintenance of a minimum level of employment at the facility. We are currently in compliance with the covenants in the lease. In addition to the PILOT Payments, we were also obligated to make an additional payment to retire a school bond previously issued by the parish in an unrelated transaction. We paid approximately $3.2 million in April 2008 in full satisfaction of this obligation. Amounts related to the revenue bond and lease obligation are presented on a net basis in our consolidated financial statements.

In conjunction with the PAA Ownership Transaction, this tax abatement agreement was valued at approximately $23 million and is reflected as a component of intangibles and other assets, net in our consolidated balance sheet.

Property Tax Matter

In December 2011, we received a property tax bill from Evangeline Parish for approximately $1.4 million related to property that we believe is tax-exempt under the lease agreement discussed above. To properly preserve our rights to dispute this billing, as required under applicable Louisiana state law, we have paid this billing, which relates to the 2011 tax year, under protest and have filed suit against Evangeline Parish seeking recovery of the amounts paid and declaratory relief that will insure our lease agreement is honored in the future. The approximately $1.4 million paid under protest is reflected as a component of other current assets on our accompanying consolidated balance sheet as of December 31, 2011. We have not recognized any property tax expense related to this matter as this billing relates to property which is exempt from taxes in accordance with the terms of the lease agreement.

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Note 14 Goodwill and Intangible Assets

The table below reflects our changes in goodwill (in thousands):

Balance at December 31, 2009	$ 24,549
Push down accounting adjustment	417
Balance at December 31, 2010	$ 24,966
Southern Pines Acquisition (See Note 3)	300,504
Balance at December 31, 2011	$ 325,470

During the year ended December 31, 2010, we recorded approximately $0.4 million of adjustments to amounts originally pushed down to us in conjunction with the PAA Ownership Transactions. Such adjustments were related to changes in estimates of income tax related asset and liabilities associated with periods prior to the PAA Ownership Transaction.

Intangibles and other assets, net consisted of the following at December 31, 2011 and 2010 (in thousands):

	Lives (In Years)	December 31, 2011	December 31, 2010
Customer contracts	2 to 10	$ 76,536	$
Property tax abatements	7 to 13	38,252	23,000
Debt issue costs[1]	5	3,802	2,441
Other long-term assets	n/a	2,201	
Total intangible and other assets		120,791	25,441
Less: Accumulated amortization		(19,062)	(2,861)
Total intangible and other assets, net of amortization		$ 101,729	$ 22,580

(1) Costs incurred in connection with the issuance of the long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Fully amortized debt issue costs and the related accumulated amortization are written-off in conjunction with the refinancing or termination of the applicable debt arrangement. Amortization of debt issuance costs is reflected as a component of depreciation, depletion, and amortization expenses in our accompanying consolidated statements of operations.

Accumulated amortization of intangible assets consisted of the following at December 31, 2011 and 2010 (in thousands):

	December 31, 2011	December 31, 2010
Customer contracts	$ (12,797)	$
Property tax abatements	(5,969)	(2,300)
Debt issue costs	(296)	(561)
Total accumulated amortization	$ (19,062)	$ (2,861)

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Amortization expense related to our intangible assets was $17.4 million, $2.3 million, $0.6 million and $1.6 million for the periods ended December 31, 2011, December 31, 2010, December 31, 2009 and September 2, 2009 respectively. We estimate that our amortization expense related to our finite lived intangible assets for the next five years will be as follows (in thousands):

Calendar Year	Expense
2012	$ 17,111
2013	$ 16,211
2014	$ 13,911
2015	$ 11,211
2016	$ 8,310

Note 15 Property and Equipment:

Property and equipment, net is stated at cost and consisted of the following at December 31, 2011 and 2010 (in thousands):

	Lives[(1)] (In Years)	December 31, 2011	December 31, 2010
Natural gas storage facilities and equipment	50 to 70	$ 1,012,405	$ 742,526
Office property, equipment and other	3 to 5	48	48
Oil and gas properties	n/a	1,986	1,986
Land	n/a	8,676	8,288
Construction work in progress	n/a	288,438	139,797
		1,311,553	892,645
Less: Accumulated depreciation and depletion		(31,140)	(14,837)
Property and equipment, net		$ 1,280,413	$ 877,808

(1) At the point of revaluing our assets to fair value in conjunction with the PAA Ownership Transaction, we also reassessed the estimated useful lives used for depreciation purposes and revised them accordingly.

Depreciation and depletion expense related to our property and equipment for the twelve months ended December 31, 2011 and 2010, the period from September 3, 2009 through December 31, 2009 and the period from January 1, 2009 through September 2, 2009 was approximately $16.3 million, $11.8 million, $3.0 million and $6.0 million, respectively.

Although our Bluewater facility includes certain oil and gas producing properties, the production of oil and gas is not our primary line of business and thus, we view these assets as ancillary to our existing operations. The terms of our agreement with the former owners of Bluewater requires us to produce these crude oil proved reserves subject to certain conditions. We have capitalized our costs to acquire such properties and such costs are depreciated and depleted by the unit of production method.

Our Pine Prairie and Southern Pines facilities are being managed, developed and constructed as separate projects. We will place assets into service in several phases and begin depreciation of these assets and an applicable portion of the other related assets when they are complete and ready for their intended use.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including condition, age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

At December 31, 2011 and 2010, the property and equipment balance includes approximately $3.0 million and $4.9 million, respectively, of accrued costs. Such amounts are reflected as a component of accounts payable and accrued liabilities in our consolidated balance sheets.

During the year ended December 31, 2011, we received cash of approximately $7.2 million under a state incentive program for jobs creation. This incentive payment, which was determined based on applicable capital expenditures, was accounted for as a refund of sales tax previously paid and reduced the carrying value of our applicable property and equipment.

Note 16 Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
		(in thousands, except per unit data)			
2011					
Revenues	$ 50,420	$ 54,364	$ 79,334	$ 158,846	$ 342,964
Gross margin[2]	$ 16,363	$ 21,938	$ 21,486	$ 27,826	$ 87,613
Operating income	$ 7,179	$ 17,297	$ 17,118	$ 23,453	$ 65,047
Net income	$ 6,345	$ 15,869	$ 15,445	$ 22,039	$ 59,698
Limited partner interest in net income[3]	$ 6,137	$ 15,470	$ 14,919	$ 21,381	$ 57,905
Basic net income per limited partner unit[3]	$ 0.10	$ 0.22	$ 0.21	$ 0.30	$ 0.85
Diluted net income per limited partner unit[3]	$ 0.10	$ 0.22	$ 0.21	$ 0.30	$ 0.85
Cash distributions per limited partner unit[3][4]	$ 0.3450	$ 0.3450	$ 0.3575	$ 0.3575	$ 1.405

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
		(in thousands, except per unit data)			
2010					
Revenues	$ 22,205	$ 24,158	$ 25,083	$ 28,841	$ 100,287
Gross margin[2]	$ 10,179	$ 13,727	$ 13,784	$ 15,403	$ 53,093
Operating income	$ 6,165	$ 9,987	$ 10,375	$ 10,601	$ 37,128
Net income	$ 3,123	$ 7,232	$ 9,620	$ 9,812	$ 29,787
Limited partner interest in net income[3][5]	$	$ 4,828	$ 9,428	$ 9,566	$ 23,822
Basic net income per limited partner unit[3][5]	$	$ 0.11	$ 0.21	$ 0.22	$ 0.54
Diluted net income per limited partner unit[3][5]	$	$ 0.11	$ 0.21	$ 0.22	$ 0.54
Cash distributions per limited partner unit[3][4]	$	$ 0.2114	$ 0.3375	$ 0.3450	$ 0.8939

(1) The sum of the four quarters may not equal the total year due to rounding.

(2) Gross margin is calculated as total revenues less (i) storage related costs, (ii) natural gas sales costs, (iii) other operating costs, (iii) fuel expense and (iv) depreciation, depletion and amortization.

(3) For all periods during 2011 and 2010, our Series B subordinated units were not entitled to participate in earnings or distributions.

(4) Represents cash distribution per distribution eligible limited partner unit earned for the quarter, which was declared and paid in the following quarter.

(5) Excludes results attributable to the period prior to the closing of the Partnership s initial public offering on May 5, 2010.

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Note 17 Operating Segments

We manage our operations through three operating segments, Bluewater, Southern Pines and Pine Prairie. We have aggregated these operating segments into one reporting segment, Gas Storage. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including adjusted EBITDA, volumes, adjusted EBITDA per thousand cubic feet (Mcf) and maintenance capital expenditures. We have aggregated our three operating segments into one reportable segment based on the similarity of their economic and other characteristics, including the nature of services provided, methods of execution and delivery of services, types of customers served and regulatory requirements. We define adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, unrealized gains and losses from derivative activities and other adjustments for the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we refer to as selected items impacting comparability or selected items. The measure above excludes depreciation, depletion and amortization as we believe that depreciation, depletion and amortization are largely offset by repair and maintenance capital investments. Maintenance capital consists of expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating capability, service capability, and/or functionality of our existing assets.

The following table reflects certain financial data for our reporting segment for the periods indicated (in thousands):

	Successor			Predecessor
	Year Ended December 31, 2011	Year Ended December 31, 2010 (See Note 1)	September 3, 2009 through December 31, 2009	January 1, 2009 through September 2, 2009 (See Note 1)
Revenues [(1)]	$ 342,964	$ 100,287	$ 25,251	$ 46,929
Adjusted EBITDA	$ 107,229	$ 53,857	$ 12,165	$ 28,701
Maintenance capital	$ 798	$ 438	$ 320	$ 384
Long-lived assets [(2)]	$ 1,756,044	$ 962,852	$ 888,164	
Total assets	$ 1,849,999	$ 998,728	$ 900,407	

(1) Approximately $49 million of natural gas sales revenues for the year ended December 31, 2011 were sold through a commodity exchange in Canada with physical delivery occurring in Canada.

(2) All of our assets are located in the United States, thus no geographic data disclosure is necessary for long-lived assets or total assets.

The following table reconciles Adjusted EBITDA to consolidated net income (in thousands):

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	Year Ended December 31, 2011	Successor Year Ended December 31, 2010 (See Note 1)	September 3, 2009 through December 31, 2009	Predecessor January 1, 2009 through September 2, 2009 (See Note 1)
Adjusted EBITDA	$ 107,229	$ 53,857	$ 12,165	$ 28,701
Selected items impacting Adjusted EBITDA:				
Equity compensation expense	(4,046)	(2,747)	(1,467)	(304)
Acquisition related costs	(4,055)	(251)		
Insurance deductible	(500)			
Mark-to-market of open derivative positions	138	370	(370)	
Depreciation, depletion and amortization	(33,714)	(14,119)	(3,578)	(8,054)
Interest expense, net of amounts capitalized	(5,354)	(7,323)	(4,262)	(4,352)
Income tax expense				(473)
Net Income	$ 59,698	$ 29,787	$ 2,488	$ 15,518

Note 18 Subsequent Events

Modification of Conversion Terms Series B Subordinated Units

In February 2012, we modified the terms of the Partnership s 13.5 million Series B subordinated units, which modification was approved by PAA, the owner of all of the Series B subordinated units. The Partnership s Series B subordinated units do not participate in quarterly distributions. Instead, the Series B subordinated units convert into Series A subordinated units or common units in five distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in our quarterly distributions. The modification increases the quarterly distribution benchmark for the first three of the five tranches, totaling 7.5 million Series B subordinated units in the aggregate, to an annualized level of $1.71 per unit. Previously, the quarterly distribution levels required to cause conversion for these three tranches were at annualized levels of $1.44, $1.53 and $1.63 per unit. The modification, which was made in recognition of the continued challenging market conditions facing the natural gas storage business, benefits common unitholders by reducing the number of units on which distributions would otherwise be required to be paid in the case of distributions below the annualized level of $1.71.

Modification of Equity Compensation Awards

In February 2012, the Board of Directors of our general partner approved the modification certain equity compensation awards previously granted under the 2010 LTIP Plan. As a result of the modification, approximately 232,500 equity-classified phantom unit awards will now vest in the following manner: (i) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in February 2012, will vest upon the date we pay an annualized distribution of at least $1.45, (ii) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in May 2013, will vest upon the date we pay an annualized distribution of at least $1.50 and (iii) the remainder, with distribution equivalent rights also modified to begin payment in May 2014, will vest upon the date we pay an annualized distribution of at least $1.55. Fifty percent of any awards that have not vested as of the November 2016 distribution date will vest at that time and the remainder will expire. Additionally, 232,500 of equity-classified phantom unit awards with vesting terms originally tied to the conversion of our Series A and Series B subordinated units were modified such that all these awards will now fully vest upon conversion of the Series A subordinated units to common units. Distribution equivalent rights were also granted with respect to the these awards beginning February 2012. There was no financial impact at the time of the modification; however, we anticipate that we will recognize additional equity compensation expense in the future as a result of the modification.

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EXHIBIT INDEX

2.1		Purchase and Sale Agreement dated December 28, 2010 by and among SGR Holdings, L.L.C., Southern Pines Energy Investment Co., LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 30, 2010).
2.2		Amendment dated May 2, 2011 to Purchase and Sale Agreement dated December 28, 2010 (incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
3.1		Certificate of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.2		Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. dated August 16, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 20, 2010).
3.3		Amendment No. 1 dated February 2, 2012 to Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 8, 2012).
3.4		Certificate of Formation of PNGS GP LLC (incorporated by reference to Exhibit 3.3 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.5		Amended and Restated Limited Liability Company Agreement of PNGS GP LLC dated May 5, 2010 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
4.1	—	Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on December 30, 2010).
4.2	—	Form of Registration Rights Agreement by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 20, 2011).
10.1		Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 4, 2010).
10.2		Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 11, 2010).
10.3		Tax Sharing Agreement dated May 5, 2010 by and among Plains All American Pipeline, L.P. and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on May 11, 2010).
10.4		Credit Agreement dated August 19, 2011 among PAA Natural Gas Storage, L.P., Bank of America, N.A., and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 25, 2011).
10.5		Employment Agreement, effective November 1, 2008, between Dean Liollio and Plains All American GP LLC (incorporated by reference to Exhibit 10.10 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
10.6		Employment Agreement, effective September 15, 2009, between Richard McGee and Plains All American GP LLC (incorporated by reference to Exhibit 10.9 to Amendment No. 3 to the Registration Statement on Form S-1 (333-164492) filed on April 13, 2010).
10.7		PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on May 11, 2010).

10.8 *		Form of Phantom Unit Grant Letter (Category 1).
10.9 *		Form of Phantom Unit Grant Letter (Category 2).
10.10		Form of PNGS GP LLC Class B Restricted Unit Agreement (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
10.11		Common Unit Purchase Agreement dated December 23, 2010 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 30, 2010).
10.12		Common Unit Purchase Agreement dated January 19, 2011 by and among PAA Natural Gas Storage, L.P. and the purchasers party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 20, 2011).
10.13		Note Payable to PAA dated February 9, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on February 14, 2011).
10.14	—	Agreement to Lease with Option to Purchase, dated May 1, 2006, between Industrial Development Board No. 1 of the Parish of Evangeline State of Louisiana, Inc. and Pine Prairie Energy Center, LLC (incorporated by reference to Exhibit 10.7 to Amendment No. 2 to the Registration Statement on Form S-1 (333-164492) filed on April 2, 2010).
10.15		Director Compensation Summary (incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-K for the year ended December 31, 2010).
21.1*		List of Subsidiaries of PAA Natural Gas Storage, L.P.
23.1*		Consent of PricewaterhouseCoopers LLP.
31.1*		Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2*		Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1*		Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2*		Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS*		XBRL Instance Document
101.SCH*		XBRL Taxonomy Extension Schema Document
101.CAL*		XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*		XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*		XBRL Taxonomy Extension Label Linkbase Document
101.PRE*		XBRL Taxonomy Extension Presentation Linkbase Document

Management compensatory plan or arrangement.

* Filed herewith.