PAA NATURAL GAS STORAGE LP
Form 10-Q
November 04, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended September 30, 2011

OR

o **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)

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. þ Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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). þ Yes o No

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

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

As of November 2, 2011, there were 59,193,825 common units outstanding. The common units trade on the New York Stock Exchange under the ticker symbol PNG.

PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PAA Natural Gas Storage, L.P. and Subsidiaries
Condensed Consolidated Balance Sheets
(unaudited)
(in thousands, except units)

	September 30, 2011	December 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$ 342	$ 346
Restricted cash		20,000
Accounts receivable	15,476	13,986
Natural gas inventory	28,348	57
Other current assets	8,058	1,487
Total current assets	52,224	35,876
Property and equipment		
Property and equipment	1,293,153	892,645
Less: Accumulated depreciation, depletion and amortization	(26,799)	(14,837)
Property and equipment, net	1,266,354	877,808
Other assets		
Base gas	45,712	37,498
Goodwill	325,470	24,966
Intangibles, net	104,288	22,580
Total other assets, net	475,470	85,044
Total assets	$ 1,794,048	$ 998,728
Liabilities and Partners Capital		
Current liabilities		
Accounts payable and accrued liabilities	$ 43,929	$ 14,006
Short-term debt	18,261	
Accrued taxes	1,544	1,009
Total current liabilities	63,734	15,015
Long-term liabilities		
Note payable to PAA	200,000	
Long-term debt under credit agreement	234,639	259,900
Other long-term liabilities	1,218	423

Total long-term liabilities		435,857		260,323
Total liabilities		499,591		275,338
Commitments and contingencies (Note 6)				
Partners capital				
Common unitholders (59,193,825 units issued and outstanding at September 30, 2011)		1,040,765		474,489
Subordinated unitholders (25,434,351 units issued and outstanding at September 30, 2011)		230,980		236,853
General partner		27,618		13,637
Accumulated other comprehensive loss		(4,906)		(1,589)
Total partners capital		1,294,457		723,390
Total liabilities and partners capital	$	1,794,048	$	998,728

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

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PAA Natural Gas Storage, L.P. and Subsidiaries
Condensed Consolidated Statements of Operations
(unaudited)
(in thousands, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenues				
Firm storage services	$ 35,536	$ 23,773	$ 100,075	$ 66,057
Hub services	1,830	689	6,465	3,625
Natural gas sales	40,718		74,787	
Other	1,250	621	2,791	1,764
Total revenues	79,334	25,083	184,118	71,446
Costs and expenses				
Storage related costs	4,770	5,101	14,908	16,624
Natural gas sales costs	40,053		72,785	
Other operating costs (except those shown below)	3,070	1,720	9,072	5,144
Fuel expense	762	611	2,964	1,665
General and administrative expenses	4,368	3,409	18,193	11,163
Depreciation, depletion and amortization	9,193	3,867	24,602	10,323
Total costs and expenses	62,216	14,708	142,524	44,919
Operating income	17,118	10,375	41,594	26,527
Other income/(expense)				
Interest expense, net of capitalized interest	(1,666)	(749)	(3,945)	(6,540)
Other income (expense)	(7)	(6)	10	(12)
Net income	$ 15,445	$ 9,620	$ 37,659	$ 19,975
Calculation of Limited Partner Interest in Net Income:				
Net income [1]	$ 15,445	$ 9,620	$ 37,659	$ 14,547
Less general partner interest in net income	526	192	1,133	291
Limited partner interest in net income	$ 14,919	$ 9,428	$ 36,526	$ 14,256
Net income per limited partner unit				
Common and Series A subordinated units [2] (Basic)	$ 0.21	$ 0.21	$ 0.54	$ 0.32
Common and Series A subordinated units [2] (Diluted)	$ 0.21	$ 0.21	$ 0.54	$ 0.32
Limited partner units outstanding				
Common and Series A subordinated units [2] (Basic)	71,125	44,520	67,279	44,902
Common and Series A subordinated units [2] (Diluted)	71,136	44,525	67,294	44,907

(1)

Amounts attributable to 2010 periods are reflective of general and limited partner interests in net income subsequent to closing of the Partnership s initial public offering on May 5, 2010.

(2) Excludes Series B subordinated units. See Note 9, Net Income per Limited Partner Unit.

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

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PAA Natural Gas Storage, L.P. and Subsidiaries
Condensed Consolidated Statement of Changes in Partners Capital
(unaudited)
(in thousands)

	Partners Capital					
		Limited Partners			Accumulated Other	
		Subordinated		General	Comprehensive	
	Common	Series A	Series B	Partner	Gain/(Loss)	Total
Balance at December 31, 2010	$ 474,489	$ 135,062	$ 101,791	$ 13,637	$ (1,589)	$ 723,390
Net income	30,047	6,479		1,133		37,659
Issuance of common units, net of offering and other costs	587,347			12,000		599,347
Equity compensation expense	664			2,369		3,033
Distributions to unitholders and general partner	(51,735)	(12,352)		(1,525)		(65,612)
Distribution equivalent right payments	(47)					(47)
Contribution from general partner				4		4
Net deferred loss on cash flow hedges					(3,317)	(3,317)
Balance at September 30, 2011	$ 1,040,765	$ 129,189	$ 101,791	$ 27,618	$ (4,906)	$ 1,294,457

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

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PAA Natural Gas Storage, L.P. and Subsidiaries
Condensed Consolidated Statements of Cash Flows
(unaudited)
(in thousands)

	Nine Months Ended September 30	
	2011	**2010**
Cash flows from operating activities		
Net income	$ 37,659	$ 19,975
Adjustments to reconcile to cash flow from operations		
Depreciation, depletion and amortization	24,602	10,323
Equity compensation expense	3,360	1,514
Non-cash interest expense on borrowings from parent, net		5,081
Unrealized gain on derivative instruments	(235)	(370)
Changes in assets and liabilities, net of acquisitions		
Accounts receivable and other assets	(17,679)	(5,882)
Accounts payable and accrued liabilities	15,320	1,585
Net cash provided by operating activities	63,027	32,226
Cash flows from investing activities		
Additions to property and equipment	(57,662)	(58,550)
Cash paid in connection with acquisition, net of cash acquired	(744,209)	
Decrease in restricted cash	20,000	
Cash paid for base gas	(5,292)	(9,488)
Other investing activities		80
Net cash used in investing activities	(787,163)	(67,958)
Cash flows from financing activities		
Borrowings under credit agreements	437,800	256,900
Repayments of borrowings under credit agreements	(444,800)	(35,400)
Borrowings from parent	200,000	24,000
Repayment of borrowings from parent		(468,363)
Net proceeds from issuance of common units	587,347	268,161
Costs incurred in connection with financing arrangements	(2,561)	(2,433)
Contributions from general partner	12,004	1
Distributions paid to unitholders	(64,086)	(9,623)
Distributions paid to general partner	(1,525)	(196)
Distribution equivalent right payments	(47)	(10)
Net cash provided by financing activities	724,132	33,037
Net increase (decrease) in cash and cash equivalents	(4)	(2,695)
Cash and cash equivalents		
Beginning of period	346	3,124
End of period	$ 342	$ 429

Cash paid for interest, net of amounts capitalized	$	2,902	$	1,448
Non-cash items				
Change in non-cash asset purchases included in accounts payable	$	1,811	$	(6,855)
Non-cash interest capitalized on borrowings from parent	$		$	5,130

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

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PAA Natural Gas Storage, L.P. and Subsidiaries
Notes to the Condensed Consolidated Financial Statements
(unaudited)

1. Organization, Nature of Operations and Basis of 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 September 30, 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 75 billion cubic feet (Bcf). During the second half of 2010, we formed PNG Marketing, LLC as a commercial optimization company. PNG Marketing engages in the purchase and sale of natural gas as well as leasing capacity and related services from third party and affiliated providers and engaging in related commercial natural gas 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 September 30, 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.

The accompanying condensed consolidated interim financial statements include the accounts of PNG and its subsidiaries, all of which are wholly owned, and should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2010 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. 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. The condensed balance sheet data as of December 31, 2010 was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP. The results of operations for the three and nine months ended September 30, 2011 should not be taken as indicative of the results to be expected for the full year.

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

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.

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.

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.

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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 September 30, 2011, PNG owned approximately 7.3 Bcf of natural gas inventory with a carrying value of approximately $28.3 million. Our natural gas inventory balance at September 30, 2011 reflects a lower of cost or market adjustment of approximately $2.6 million. The recognition of this adjustment, a component of natural gas sales costs in our accompanying condensed consolidated statement of operations, was offset by the recognition of approximately $2.6 million of unrealized gains on derivative instruments (see Note 4) being utilized to hedge the future sales of our natural gas inventory.

Property and Equipment

During the nine months ended September 30, 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.

2. Recent Accounting Pronouncements

Other than as discussed below and in our 2010 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the nine months ended September 30, 2011 that are of significance or potential significance to us.

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 public entities, for impairment tests performed during entities fiscal years (and interim periods within those years) that begin after December 15, 2010. Early application is not permitted. 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 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. Early adoption is permitted. 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. A fair value measurement is designated as level 1, 2 or 3 within the hierarchy 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 reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted this guidance on January 1, 2011. See Note 4 for additional disclosure. Our adoption did not have any material impact on our financial position, results of operations, or cash flows.

Accounting Pronouncements Not Yet Effective

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. Early adoption is 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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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.

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, with earlier adoption prohibited. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

3. Acquisition

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, which is subject to finalization of certain post-closing adjustments, was approximately $752 million, net of cash acquired.

The allocation of fair value to 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
PP&E	341	5 70
Base Gas	3	n/a
Other working capital, net of cash acquired	1	n/a
Intangible assets	92	2 10
Goodwill	301	n/a
Total	$ 752	

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 is estimated to be approximately $12.8 million, $14.2 million, $13.3 million, $11.0 million and $8.3 million for the five full or partial calendar years following the acquisition date, 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

2011.

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).

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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 7).

During the nine months ended September 30, 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 condensed consolidated statement of operations.

Goodwill included in our condensed consolidated balance sheets was approximately $325 million and $25 million as of September 30, 2011 and December 31, 2010, respectively.

In May 2011, we entered into an agreement with the former owners of SG Resources Mississippi, LLC 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 by us have been and will continue to be used to fund anticipated facility development and other related costs identified subsequent to closing. Additionally, the parties executed releases of any existing and future claims, subject to customary carve-outs.

Pro Forma Results

Total revenues generated by our Southern Pines facility of approximately $12.6 million for the three months ended September 30, 2011 and approximately $30.8 million for the period from February 9, 2011 (date of acquisition) through September 30, 2011 are included in our condensed consolidated statements of operations for the three and nine months ended September 30, 2011, respectively. 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 nine months ended September 30, 2011 and 2010, assuming the Southern Pines Acquisition had occurred on January 1, 2010, are presented below (in thousands, except per unit amounts):

	Nine Months Ended September 30,	
	2011	**2010**
Total revenues	$ 188,081	$ 98,581
Net income(1)	$ 42,963	$ 27,635
Limited partner interest in net income(2)	$ 41,723	$ 22,623
Net income per limited partner unit(3)		
Basic	$ 0.59	$ 0.31
Diluted	$ 0.59	$ 0.31

(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 9, Net Income per Limited Partner Unit.

4. 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 on commodity price changes. We use various derivative instruments to (i) manage our price exposure associated with anticipated purchases or sales of natural gas, (ii) economically hedge the value of our natural gas storage facilities and

(iii) 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 a hedge and on an ongoing basis, we assess whether the derivatives used in such hedging transactions are highly effective in offsetting changes in cash flows of hedged items. FASB guidance requires us to recognize changes in the fair value of derivative instruments currently in earnings unless the derivatives meet specific cash flow hedge accounting requirements, in which case the effective portion of changes in the fair value of cash flow hedges are deferred in accumulated other comprehensive income (AOCI) and reclassified into earnings when the underlying hedged transaction affects earnings.

Commodity Price Risk Hedging

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 September 30, 2011, we have a long swap position of approximately 2.0 Bcf through April 2013 related to anticipated base gas purchases. Additionally, our dedicated commercial optimization company captures short-term market opportunities by leasing a portion of our owned or leased storage capacity and engaging in related commercial optimization activities. We use various derivatives, including index and basis swaps, to hedge anticipated purchases and sales of natural gas by our commercial optimization company. As of September 30, 2011, we have a short swap position of approximately 14.3 Bcf through December 2011 related to anticipated sales of natural gas, and an approximate 5.9 Bcf long swap position through December 2011 related to anticipated purchases of natural gas.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the underlying benchmark interest rate associated with borrowings outstanding under our debt facilities. During June 2011 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.

Summary of Financial Statement Impact

Derivatives that qualify for hedge accounting are generally designated as cash flow hedges. Changes in fair value for the effective portion of the hedges are deferred in AOCI and reclassed to earnings in the periods during which the underlying hedged transaction impacts earnings. Derivatives that do not qualify or were not designated for hedge accounting and the ineffective portion of cash flow hedges are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

Our accounting policy is to offset fair value amounts associated with derivatives 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 fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of September 30, 2011, we had a net broker receivable of approximately $6.1 million (consisting of initial margin of $4.4 million increased by $1.7 million of variation margin posted by us). Our interest rate derivatives, which are over-the-counter instruments, do not have margin requirements. At September 30, 2011, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact upon a change in our credit standing.

A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2011 is as follows (in thousands):

Three Months Ended September 30, 2011

Location of Gain/(Loss)	Derivatives in Hedging Relationships[1][2][4]	Derivatives not Designated as a Hedge[3]	Total
Commodity Derivatives			
Natural Gas Sales	$ 60	$ (50)	$ 10
Natural Gas Sales Costs	2,615		2,615
Other Revenues	211	(11)	200
Interest Rate Derivatives			
Interest Expense	(147)		(147)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 2,739	$ (61)	$ 2,678

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	Nine Months Ended September 30, 2011		
Location of Gain/(Loss)	Derivatives in Hedging Relationships(1)(2)(4)	Derivatives not Designated as a Hedge(3)	Total
Commodity Derivatives			
Natural Gas Sales	$ 1,713	$ 45	$ 1,758
Natural Gas Sales Costs	2,615		2,615
Other Revenues	243	61	304
Interest Rate Derivatives			
Interest Expense	(175)		(175)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 4,396	$ 106	$ 4,502

(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 represent the ineffective portion of our cash flow hedges recognized in earnings.

(3) Includes realized and unrealized gains or losses for derivatives that did not qualify or were not designated for hedge accounting during the period.

(4) Includes unrealized gains of approximately $2.6 million reclassified from AOCI to earnings during the period to offset a lower of cost or market adjustment relating to the carrying value of our inventory.

During the three and nine months ended September 30, 2010, our earnings were not impacted from derivative activities in cash flow hedging relationships.

We recognized realized losses of approximately $0.8 million, of which approximately $0.4 million was incurred during the nine months ended September 30, 2010, associated with a natural gas calendar spread position, which was closed in June 2010 and did not qualify for hedge accounting. Such losses are reflected as a component of other revenues in our accompanying condensed consolidated statements of operations.

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of September 30, 2011 (in thousands):

	As of September 30, 2011			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity Derivatives	Other current assets	$ 7,496	Other current assets	$ (8,215)

			Other long-term liabilities		(515)
Interest Rate Derivatives			Other current liabilities		(342)
			Other long-term liabilities		(361)
Total Derivatives designated as hedging instruments	$	7,496		$	(9,433)

	As of September 30, 2011			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives not designated as hedging instruments:				
Commodity Derivatives	Other current assets	$ 285	Other current assets	$ (669)
Total Derivatives designated as hedging instruments		$ 285		$ (669)
Total Derivatives		$ 7,781		$ (10,102)

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

	As of December 31, 2010			
	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)

Accumulated Other Comprehensive Income

During the nine months ended September 30, 2011, we recognized a net loss in AOCI of $3.3 million. The $3.3 million net deferred loss consisted of net deferred gains of $1.1 million for the period offset by net reclassification adjustments of $4.4 million. Reclassification adjustments reflect amounts reclassified to earnings from AOCI to coincide with the earnings impact of the respective hedged transactions. Reclassification adjustments which reduce AOCI result in an offsetting increase to current period earnings and those which increase AOCI result in an offsetting decrease to current period earnings. The net reclassification adjustment of $4.4 million for the nine month period ended September 30, 2011, which reduced AOCI and increased current period earnings, includes a deferred gain of approximately $2.6 million which offsets a lower of cost or market adjustment related to the carrying value of our natural gas inventory.

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 anticipated base gas purchases. 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. Deferred losses of $2.4 million associated with base gas hedges are included in AOCI as of September 30, 2011. Remaining amounts in AOCI as of September 30, 2011 associated with both open and settled derivative positions. Of the total deferred loss in AOCI of

$4.9 million as of September 30, 2011, approximately $2.3 million is expected to be reclassed to earnings during the next twelve months. Amounts deferred are based on market prices as of September 30, 2011, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. Additionally, during the nine months ended September 30, 2011, we reclassified a gain of $0.7 million from AOCI to natural gas sales when it was deemed probable that the anticipated hedged transactions would not occur.

Fair Value Measurements

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 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The determination of fair value incorporates various factors. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements, but also the impact of potential nonperformance risk on our liabilities. As of September 30, 2011 and December 31, 2010 and during the three and nine months ended September 30, 2011 and 2010, all of our commodity derivatives utilized consisted of exchange-traded or exchange-cleared instruments within active markets. We therefore consider all of our commodity derivatives as of September 30, 2011 and December 31, 2010 and during the three and nine month periods ended September 30, 2011 and 2010 to be Level 1 fair value measurements.

We consider our interest rate derivatives to be within Level 2 of the fair value hierarchy. The fair value of these instruments is based on broker or dealer price quotations which are corroborated with market observable inputs including forward interest rates obtained from pricing services.

5. Debt

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, 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 September 30, 2011, borrowings of approximately $252.9 million were outstanding under our new credit agreement, which includes approximately $52.9 million under the revolving credit facility. The weighted average interest rate on all borrowings outstanding under our new credit agreement as of September 30, 2011 was approximately 1.8%. 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 hedged natural gas inventory. At December 31, 2010, borrowings of approximately $260 million were outstanding under PNG s previous revolving credit facility.

Our revolving credit facility includes the ability to issue letters of credit. As of September 30, 2011, we had $3.0 million of outstanding letters of credit under our revolving credit facility.

As of September 30, 2011, we were in compliance with the covenants required by our new credit agreement.

In conjunction with the modification of our credit agreements, 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. 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.

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 during the nine months ended September 30, 2011 was approximately $4.1 million.

Capitalized interest for the three and nine months ended September 30, 2011 was $2.7 million and $8.4 million, respectively, and $1.0 million and $6.5 million for the three and nine months ended September 30, 2010, respectively.

6. Commitments and Contingencies

Environmental

We may experience releases of natural gas, brine, crude oil 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 releases from our assets may substantially affect our business. As of September 30, 2011, we have not identified any such material obligations.

A natural gas storage facility, associated pipeline header system and gas handling and compression facilities may suffer 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 or destruction of property, base gas, or equipment, pollution or environmental damage, or suspension of operations. We maintain insurance under PAA s insurance program, of various types that we consider adequate to cover our operations and properties. Such insurance covers our assets in amounts management considers 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 facilities, associated pipeline header systems, and gas handling and compression facilities. 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, we expect this trend to continue as we continue to grow and expand. Accordingly, we may 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 condition, results of operations or cash flows.

Insurance

We participate in an insurance program managed by PAA. Due to recent increases in cost combined with stricter coverage limitations, we have 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 three months ended September 30, 2011, we received $3.0 million of property insurance proceeds related to the January 2011 operational incident and fire at our Bluewater facility.

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.

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7. Partners Capital and Distributions

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. 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.

Outstanding Units

From December 31, 2010 through September 30, 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, 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, September 30, 2011	59,193,825	11,934,351	13,500,000	84,628,176

Distributions

The following table details the distributions declared for 2011 quarterly periods or paid during the nine months ended September 30, 2011 (in millions, except per unit amounts):

		Distributions Paid					Distributions
			Series A	General Partner			
Date Declared	Date Paid or To Be Paid	Common Units	Subordinated Units	Incentive	2%	Total	per limited partner unit
October 11, 2011	November 14, 2011[1]	$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

(1) Payable to unitholders of record on November 4, 2011, for the period July 1, 2011 through September 30, 2011

8. 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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	$ 15,445	$ 9,620	$ 37,659	$ 19,975
Net loss on cash flow hedges	(3,573)	(44)	(3,317)	(403)
Total comprehensive income	$ 11,872	$ 9,576	$ 34,342	$ 19,572

9. 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, which is to be paid in the subsequent quarter (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.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2011 (amounts in thousands, except per unit data):

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Net income	$ 15,445	$ 37,659
Less: Incentive distributions due to general partner	222	388
Less: General partner s 2% ownership interest	304	745
Net income available to limited partners	$ 14,919	$ 36,526
Numerator for basic and diluted earnings per limited partner unit:		
Allocation of net income amongst limited partner interests:		
Net income allocable to common units	$ 12,416	$ 30,047
Net income allocable to Series A subordinated units	2,503	6,479
Net income allocable to Series B subordinated units [(1)]		
Net income available to limited partners	$ 14,919	$ 36,526
Denominator:		
Basic weighted average number of limited partner units outstanding:[(1)(2)(3)]		
Common units	59,191	55,345
Series A subordinated units	11,934	11,934
Series B subordinated units		
Diluted weighted average number of limited partner units outstanding:[(1)(2)(3)]		
Common units	59,202	55,360
Series A subordinated units	11,934	11,934
Series B subordinated units		
Basic and diluted net income per limited partner unit: [(1)(2)(3)]		
Common units	$ 0.21	$ 0.54
Series A subordinated units	$ 0.21	$ 0.54
Series B subordinated units	$	$

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The following table sets forth the computation of basic and diluted earnings per limited partner unit for the period from May 5, 2010 (the closing of our initial public offering) through September 30, 2010 (amounts in thousands, except per unit data):

	Three Months Ended September 30, 2010		May 5, 2010 Through September 30, 2010	
Net income	$	9,620	$	14,547
Less: Incentive distributions due to general partner				
Less: General partner s 2% ownership interest		192		291
Net income available to limited partners	$	9,428	$	14,256
Numerator for basic and diluted earnings per limited partner unit:				
Allocation of net income amongst limited partner interests:				
Net income allocable to common units	$	6,686	$	10,024
Net income allocable to Series A subordinated units		2,742		4,232
Net income allocable to Series B subordinated units (1)				
Net income available to limited partners	$	9,428	$	14,256
Denominator:				
Basic weighted average number of limited partner units outstanding: (1)(2)(3)				
Common units		31,586		31,585
Series A subordinated units		12,934		13,317
Series B subordinated units				
Diluted weighted average number of limited partner units outstanding: (1)(2)(3)				
Common units		31,591		31,590
Series A subordinated units		12,934		13,317
Series B subordinated units				
Basic and diluted net income per limited partner unit: (1)(2)(3)				
Common units	$	0.21	$	0.32
Series A subordinated units	$	0.21	$	0.32
Series B subordinated units	$		$	

(1) For each of the 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.

(2) Substantially all of our LTIP awards (described in Note 10), which are classified as equity awards, contain provisions whereby vesting occurs only upon the satisfaction of a performance condition. None of the

performance conditions on such awards had been satisfied during any of the periods presented. As such, our outstanding LTIP awards as of September 30, 2011 did not have a material impact in our determination of diluted net income per limited partner unit.

(3) 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 September 30, 2011 therefore, there is no dilutive impact of such units in our determination of diluted net income per limited partner unit.

10. Equity Compensation Plans

Long Term Incentive Plan (LTIP)

For discussion of our equity compensation awards, see Note 10 to our consolidated financial statements included in Part IV of our 2010 Annual Report on Form 10-K.

Our equity compensation activity for awards denominated in PNG units is summarized in the following table (units in thousands):

	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2010	623	$	19.42
Granted	24	$	22.06
Vested	(9)	$	23.31
Cancelled or forfeited	(30)	$	19.14
Outstanding, September 30, 2011	608	$	19.48

The table below summarizes the expense recognized and unit or cash settled vestings related to all of our equity compensation plans during the three and nine months ended September 30, 2011 and 2010 (in thousands):

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
Equity compensation expense [1][2][3]	$	702	$	671	$	3,360	$	1,514
LTIP cash settled vestings	$		$	317	$	580	$	471
DER cash payments	$	19	$	10	$	57	$	10

(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 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 $0.5 million and $2.4 million of compensation expense associated with these awards during the three and nine months ended September 30, 2011.

(2) Equity compensation expense for the nine months ended September 30, 2010 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 nine months ended September 30, 2011 includes approximately $3.0 million of expense associated with equity-classified awards, including approximately $2.4 million associated with the transaction awards.

11. Related Party Transactions

We do not directly employ any personnel 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 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 accompanying condensed consolidated statements of operations 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. We reimburse PAA for costs related to equity-based compensation awards upon vesting of the awards. 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. Total costs reimbursed by us to PAA for the three and nine months ended September 30, 2011, were $5.7 million and $14.7 million, respectively; and $4.6 million and $16.0 million for the three and nine months ended September 30, 2010, respectively. Of these amounts approximately $0.9 million and $2.7 million and $0.8 million and $2.6 million, during the three and nine month periods ended September 30, 2011 and 2010, 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 program.

As of September 30, 2011 and December 31, 2010, PNG had amounts due to PAA of approximately $0.2 million and $0.6 million, respectively, included in accounts payable and accrued liabilities on our accompanying condensed consolidated balance sheet.

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As of September 30, 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 $0.9 million and $1.0 million, respectively. Approximately $0.5 million and $0.6 million of such amounts were reflected in accounts payable and accrued liabilities in our accompanying condensed consolidated balance sheets as of September 30, 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 September 30, 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 September 30, 2011 under such guarantees and no payments were made to PAA under such guarantees during the three and nine months ended September 30, 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 three and nine months ended September 30, 2011, we incurred approximately $16,000 and $20,000 of expense under our obligation to reimburse PAA for administrative costs incurred in conjunction with providing parental guarantees on our behalf.

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 CDM Max, 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 CDM Max. Pursuant to these agreements, (i) our Pine Prairie subsidiary and CDM Max agreed upon the terms pursuant to which CDM Max would be allowed to connect its natural gas processing facility to Pine Prairie s header system, including the agreement by Pine Prairie to reimburse CDM Max for approximately $1.5 million of capital costs associated with construction of certain of such interconnect facilities, (ii) CDM Max 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 CDM Max s facility to CDM Max 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 three and nine months ended September 30, 2011, we recognized approximately $0.8 million of revenues from sales of natural gas to CDM Max.

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.

12. Reporting Segment

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 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues [1]	$ 79,334	$ 25,083	$ 184,118	$ 71,446
Adjusted EBITDA	$ 26,858	$ 14,907	$ 73,865	$ 37,982
Maintenance capital	$ 51	$ 75	$ 266	$ 292
Long-lived assets [1][2]	$ 1,741,824	$ 946,734	$ 1,741,824	$ 946,734
Total assets [2]	$ 1,794,048	$ 962,078	$ 1,794,048	$ 962,078

(1) We only have operations in the United States, thus no geographic data disclosure is necessary for revenues or long-lived assets.

(2) Amounts are as of September 30.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Adjusted EBITDA	$ 26,858	$ 14,907	$ 73,865	$ 37,982
Selected items impacting Adjusted EBITDA:				
Equity compensation expense	(681)	(671)	(3,339)	(1,514)
Mark-to-market of open derivative positions	132		235	370
Acquisition-related expenses	(5)		(4,055)	
Insurance deductible related to property damage incident			(500)	
Depreciation, depletion and amortization	(9,193)	(3,867)	(24,602)	(10,323)
Interest expense, net of capitalized interest	(1,666)	(749)	(3,945)	(6,540)
Net Income	$ 15,445	$ 9,620	$ 37,659	$ 19,975

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2010 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the condensed consolidated financial statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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 further discussion regarding the Partnership s initial public offering, please see the consolidated financial statements included in the Partnership s 2010 Annual Report on Form 10-K.

Overview of Operating Results, Capital Spending and Significant Activities

Adjusted EBITDA for the nine months ended September 30, 2011 was approximately $73.9 million, a 94% increase over Adjusted EBITDA of approximately $38.0 million for nine months ended September 30, 2010. This increase was primarily the result of the completion of the Southern Pines Acquisition on February 9, 2011 and 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. See Results of Operations for further discussion and analysis of our operating results. Excluding acquisitions, expansion capital expenditures for the nine months ended September 30, 2011 were approximately $66.3 million. Additionally, 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. See Liquidity and Capital Resources Overview for further discussion.

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Results of Operations

The tables below summarize our results of operations for the periods indicated (in thousands, except working capacity and monthly operating metrics data):

	Three Months Ended September 30, 2011	2010	Favorable/(Unfavorable) Variance[1] $	%
Revenues				
Firm Storage Services				
Reservation fees	$ 33,862	$ 22,487	$ 11,375	51%
Cycling fees and fuel-in-kind	1,674	1,286	388	30%
Hub Services	1,830	689	1,141	166%
Natural Gas Sales	40,718		40,718	
Other	1,250	621	629	101%
Total revenue	$ 79,334	$ 25,083	$ 54,251	216%
Storage related costs	$ (4,770)	$ (5,101)	$ 331	6%
Natural gas sales costs	(40,053)		(40,053)	
Operating costs (except those shown below)	(3,070)	(1,720)	(1,350)	(78)%
Fuel expense	(762)	(611)	(151)	(25)%
General and administrative expenses	(4,368)	(3,409)	(959)	(28)%
Interest income and other income (expense), net	(7)	(6)	(1)	
Acquisition-related expenses	5			
Insurance deductible related to property damage incident				
Equity compensation expense	681	671		
Mark-to-market of open derivative positions	(132)			
Adjusted EBITDA	$ 26,858	$ 14,907	$ 11,951	80%
Reconciliation to net income				
Adjusted EBITDA	$ 26,858	$ 14,907	$ 11,951	80%
Depreciation, depletion and amortization	(9,193)	(3,867)	(5,326)	(138)%
Interest expense, net of capitalized interest	(1,666)	(749)	(917)	(122)%
Equity compensation expense	(681)	(671)		
Acquisition-related expenses	(5)			
Mark-to-market of open derivative positions	132			
Insurance deductible related to property damage incident				
Net income	$ 15,445	$ 9,620	$ 5,825	61%
Operating Data:				
Net revenue margin[2][3]	$ 34,379	$ 19,982	$ 14,397	72%
Other operating expenses / G&A / Other	(7,521)	(5,075)	(2,446)	(48)%

Adjusted EBITDA	$ 26,858	$ 14,907	$ 11,951	80%
Average working capacity (Bcf)	74.6	50.0	24.6	49%
Average Monthly Operating Metrics ($/Mcf):				
Net revenue margin (2)(3)	$ 0.15	$ 0.13	$ 0.02	15%
Operating expenses / G&A / Other	(0.03)	(0.03)		
Adjusted EBITDA	$ 0.12	$ 0.10	$ 0.02	20%

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	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Favorable/(Unfavorable) Variance[1] $	Favorable/(Unfavorable) Variance[1] %
Revenues				
Firm Storage Services				
Reservation fees	$ 94,147	$ 62,172	$ 31,975	51%
Cycling fees and fuel-in-kind	5,928	3,885	2,043	53%
Hub Services	6,465	3,625	2,840	78%
Natural Gas Sales	74,787		74,787	
Other	2,791	1,764	1,027	58%
Total revenue	$ 184,118	$ 71,446	$ 112,672	158%
Storage related costs	$ (14,908)	$ (16,624)	$ 1,716	10%
Natural gas sales costs	(72,785)		(72,785)	
Operating costs (except those shown below)	(9,072)	(5,144)	(3,928)	(76)%
Fuel expense	(2,964)	(1,665)	(1,299)	(78)%
General and administrative expenses	(18,193)	(11,163)	(7,030)	(63)%
Interest income and other income (expense), net	10	(12)		
Acquisition-related expenses	4,055			
Insurance deductible related to property damage incident	500			
Equity compensation expense	3,339	1,514		
Mark-to-market of open derivative positions	(235)	(370)		
Adjusted EBITDA	$ 73,865	$ 37,982	$ 35,883	94%
Reconciliation to net income				
Adjusted EBITDA	$ 73,865	$ 37,982	$ 35,883	94%
Depreciation, depletion and amortization	(24,602)	(10,323)	(14,279)	(138)%
Interest expense, net of capitalized interest	(3,945)	(6,540)	2,595	40%
Equity compensation expense	(3,339)	(1,514)		
Acquisition-related expenses	(4,055)			
Mark-to-market of open derivative positions	235	370		
Insurance deductible related to property damage incident	(500)			
Net income	$ 37,659	$ 19,975	$ 17,684	89%
Operating Data:				
Net revenue margin[2][3]	$ 96,190	$ 54,452	$ 41,738	77%
Other operating expenses / G&A / Other	(22,325)	(16,470)	(5,855)	(36)%
Adjusted EBITDA	$ 73,865	$ 37,982	$ 35,883	94%

Average working capacity (Bcf)		69.4		46.0		23.4	51%
Average Monthly Operating Metrics ($/Mcf):							
Net revenue margin (2)(3)	$	0.15	$	0.13	$	0.02	15%
Operating expenses / G&A / Other		(0.03)		(0.04)		0.01	25%
Adjusted EBITDA	$	0.12	$	0.09	$	0.03	33%

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

(2) Net revenue margin equals total revenues minus storage related and natural gas sales costs.

(3) Net revenue margin excludes the impact of mark-to-market of open derivative positions.

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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, unrealized 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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Adjusted EBITDA reconciliation				
Net income	$ 15,445	$ 9,620	$ 37,659	$ 19,975
Interest expense, net of amounts capitalized	1,666	749	3,945	6,540
Depreciation, depletion and amortization	9,193	3,867	24,602	10,323
Selected items impacting Adjusted EBITDA				
Equity compensation expense	681	671	3,339	1,514
Acquisition-related expenses	5		4,055	
Mark-to-market of open derivative positions	(132)		(235)	(370)
Insurance deductible related to property damage incident			500	
Adjusted EBITDA	**$ 26,858**	**$ 14,907**	**$ 73,865**	**$ 37,982**
Distributable cash flow reconciliation				
Net income	$ 15,445	$ 9,620	$ 37,659	$ 19,975
Depreciation, depletion and amortization	9,193	3,867	24,602	10,323
Acquisition-related expenses	5		4,055	
Maintenance capital expenditures	(51)	(75)	(266)	(292)
Other non cash items:				
Equity compensation expense, net of cash payments	683	354	2,722	1,043
Mark-to-market of open derivative positions	(132)		(235)	(370)
Distributable cash flow	**$ 25,143**	**$ 13,766**	**$ 68,537**	**$ 30,679**

Three Months Ended September 30, 2011 as Compared to the Three Months Ended September 30, 2010

Revenues, Volumes and Related Costs. As noted in the table above, our total revenue and related costs increased during the three months ended September 30, 2011 (the 2011 period) when compared to the three months ended September 30, 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, LLC, (our commercial optimization company), incremental revenues attributable to the expansion of our working gas capacity at the Pine Prairie facility by approximately 8 Bcf during 2011, and additional leasing of 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 by approximately 8 Bcf during 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 leased transportation assets.

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Natural gas sales Natural gas sales of approximately $40.7 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. Crude oil sales increased slightly in the 2011 period as compared to the 2010 period by approximately $0.1 million. The increase was due to both increased volumes sold as a result of our liquids removal efforts at our Bluewater facility and higher average realized prices in the 2011 period as compared to the 2010 period. Other revenues for the 2011 period include approximately $0.4 million from a gas processing agreement with CDM Max, an affiliate of PAA, which was entered into during 2011 and approximately $0.1 million of income as a result of ineffectiveness on certain hedge positions. No ineffectiveness on hedge positions was recognized during the 2010 period.

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 $40.1 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.

Fuel expense Fuel expense increased in the 2011 period as compared to 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. Additionally, during the 2011 period we recognized approximately $0.5 million of equity compensation expense associated with awards granted by PAA. Although we will not bear the economic burden of these awards, we benefit from the services underlying these awards.

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 8 Bcf of storage capacity placed into service at our Pine Prairie facility in April 2011. Additionally, amortization of intangible assets acquired in conjunction with the Southern Pines Acquisition was approximately $4.1 million during the 2011 period.

Interest expense, net of capitalized interest Interest expense, net of capitalized interest, increased in the 2011 period when compared to the 2010 period. Interest expense, on a gross basis, increased to approximately $4.4 million in the 2011 period as compared to approximately $1.7 million in the 2010 period. Interest expense, on a gross basis, increased due to higher average debt balances outstanding in the 2011 period as compared to the 2010 period in addition to a higher average interest rate in the 2011 period as compared to the 2010 period. Capitalized interest was approximately $2.7 million and $1.0 million in the 2011 and 2010 periods, respectively. Capitalized interest was impacted from the increase in average debt balance outstanding and an increase in average interest rate in the 2011 period as compared to the 2010 period, along with an increase in assets not yet in-service as a result of the Southern Pines Acquisition.

Nine Months Ended September 30, 2011 as Compared to the Nine Months Ended September 30, 2010

Revenues, Volumes and Related Costs. As noted in the table above, our total revenue and related costs increased during the nine months ended September 30, 2011 (the 2011 period) when compared to the nine months ended September 30, 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, LLC (our commercial optimization company), 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 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 by approximately 8 Bcf and 10 Bcf during 2011 and 2010, respectively.

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 leased transportation assets.

Natural gas sales Natural gas sales of approximately $74.8 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. Crude oil sales were consistent in the 2011 period as compared to the 2010 period. A decrease in crude oil sales volumes in the 2011 period as compared to the 2010 period, primarily attributable to a temporary stoppage in liquids removal efforts at our Bluewater facility as a result of the operational incident and related fire that occurred in January 2011, was offset by higher average realized prices in the 2011 period as compared to the 2010 period. The 2010 period includes losses of approximately $0.4 million associated with changes in the fair market value of a natural gas storage related futures derivative position. During the second quarter of 2010, we closed out these positions at a realized loss of approximately $0.8 million. Other revenues for the 2011 period include approximately $0.4 million from a gas processing agreement with CDM Max, an affiliate of PAA, which was entered into during 2011 and approximately $0.2 million of income as a result of ineffectiveness on certain hedge positions. No ineffectiveness on hedge positions was recognized during the 2010 period.

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 increased in leased transportation assets in the 2011 period as compared to the 2010 period.

Natural gas sales costs Natural gas sales costs of approximately $72.8 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 establishment of our commercial optimization group, along with additional administrative costs associated with being a public company. Additionally, during the 2011 period we recognized approximately $2.4 million of equity compensation expense associated with awards granted by PAA compared to approximately $0.4 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 $2.1 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 8 Bcf and 10 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 $10.6 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, decreased to approximately $12.4 million in the 2011 period as compared to approximately $13.0 million in the 2010 period. The decrease principally resulted from a decrease in average interest rates in the 2011 period as compared to 2010 period and was partially offset by an increase in average outstanding debt balances in the 2011 period as compared to the 2010 period. Capitalized interest was approximately $8.4 million and $6.5 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.

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 softened throughout 2010 continuing into 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 (i) a relatively balanced supply/demand situation with increased shale gas production being offset by incremental consumption associated with historically abnormal weather patterns, (ii) the perception of lower gas supply risk due to a higher percentage of overall supply coming from domestic shale gas production, (iii) pipeline infrastructure additions and (iv) on a regional basis, increased storage on storage competition from capacity additions and re-contracting activities. Market conditions weakened progressively in the second half of 2010 continuing into 2011 with seasonal spreads, as reflected by the October 2011 to January 2012 NYMEX spread, decreasing to a five-year low of $0.371 per dekatherm during June 2011.

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 continue to grow our cash flows for the next few years even if such conditions persist, albeit at lower levels of growth than would have been experienced in a strong market environment. We also believe we are reasonably well positioned to pursue and consummate additional acquisitions.

However, if weak gas storage market conditions persist, 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 a continuation or further deterioration of such weak gas storage market conditions, or that our acquisition and organic growth efforts will be successful.

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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 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 facility. 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.

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 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 September 30, 2011, borrowings of approximately $252.9 million were outstanding under our new credit agreement, which includes approximately $52.9 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 September 30, 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 September 30, 2011 our total available debt would be limited to approximately $118 million of the $450 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.

In October 2011, we executed a series of NYMEX swaps to hedge 2,000 barrels per month of anticipated 2012 crude oil sales (aggregate 24,000 barrels) at our Bluewater facility.

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 also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. We have not issued any securities under the Traditional Shelf or the WKSI Shelf.

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.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing all the various aspects of the Act have not yet been issued. Our current assessment is that we may have additional documentation and reporting requirements. We will continue to monitor the final rules and regulations as they develop.

Cash Flows

As of September 30, 2011, we had a working capital deficit of approximately $11.5 million.

The following table presents a summary of our cash flows for the nine months ended September 30, 2011 and 2010 (in thousands):

	Nine Months Ended September 30,	
	2011	**2010**
Net cash provided by (used in):		
Operating activities	$ 63,027	$ 32,226
Investing activities	(787,163)	(67,958)
Financing activities	724,132	33,037
Net increase/(decrease) in cash	$ (4)	$ (2,695)
Adjusted EBITDA	$ 73,865	$ 37,982

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.

Investing Activities. Our investing activities for each of the periods listed above primarily relate to the continued expansion of our Pine Prairie facility and the acquisition of the related base gas required to operate the facility. 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. To fund these expenditures we made borrowings under our available debt facilities, including borrowings from PAA, and received capital contributions from our equity owners.

Capital Requirements

We use cash primarily for our acquisition activities, 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.

Estimated Capital Expenditures. Excluding acquisitions, we estimate we will spend approximately $93 million in expansion capital, including capitalized interest, during 2011, of which approximately $66.3 million was incurred through September 30, 2011. Maintenance capital expenditures for 2011 are estimated to be approximately $0.8 million, of which approximately $0.3 million was incurred through September 30, 2011.

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 November 14, 2011, we will pay a quarterly distribution of $0.3575 per unit on our common units and Series A subordinated units.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreement to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

See Note 6 to the condensed consolidated financial statements.

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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.

The following table includes our best estimate of the amount and timing of the payments due under our contractual obligations as of September 30, 2011 (in millions):

	Total	2011	2012	2013	2014	2015	Thereafter
Long-term debt, interest and fees (1)	$503	$ 25	$15	$14	$206	$4	$239
Leases storage, transportation, other	31	4	13	7	5	2	
Capital commitments	28	11	2	2	1	2	10
Other long-term liabilities	2		1	1			
Subtotal	$564	$ 40	$31	$24	$212	$8	$249
Natural gas purchases (2)	136	136					
Total	$700	$176	$31	$24	$212	$8	$249

(1) Includes interest payments and commitment fees on our senior unsecured credit agreement and note payable to PAA.

(2) Amounts are based on estimated volumes and market prices based on average activity during September 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. In connection with our use of certain leased storage and transportation assets, we have periodically provided certain suppliers with irrevocable standby letters of credit to secure our obligations for the purchase of these services. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the services are provided. Our $450 million senior unsecured credit agreement provides us with the ability to issue letters of credit. As of September 30, 2011, we had approximately $3 million of outstanding letters of credit under our credit facility and approximately $31 million of outstanding parental guarantees issued by PAA to third parties on behalf of PNG Marketing.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Recent Accounting Pronouncements

See Note 2 to the condensed consolidated financial statements.

Critical Accounting Policies and Estimates

For discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2010 Annual Report on Form 10K.

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, inter forecast, as well as similar expressions and statements 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. 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 short term optimization revenues from transactions involving uncontracted or unutilized capacity at our facilities;

the effects of competition;

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;

the impact of operational 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, and cavern temperature variances;

risks related to the 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;

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;

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;

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;

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

increased costs or unavailability of insurance;

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

future developments and circumstances at the time distributions are declared; and

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

Other factors, described herein, or 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.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included in our 2010 Annual Report on Form 10-K. There have been no material changes to that information other than as discussed below. Also, see Note 4 to the condensed consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

The fair value of our outstanding natural gas derivatives as of September 30, 2011 was a net liability of approximately $1.6 million. A 10% increase in natural gas prices would result in a net liability of approximately $4.2 million. A 10% decrease in natural gas prices would result in a net asset of approximately $1.0 million.

Interest Rate Price Risk

The fair value of our outstanding interest rate swap agreements as of September 30, 2011 was a net liability of approximately $0.7 million. A 10% increase in interest rates would result in a net liability of approximately $0.5 million. A 10% decrease in interest rates would result in a net liability of approximately $0.9 million.

Item 4. 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 (i) information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) such information 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, and has 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.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. 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.

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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.

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PART II.
OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. Also, see Note 6 to the condensed consolidated financial statements for additional discussion regarding legal proceedings.

Item 1A. Risk Factors

For a discussion regarding our risk factors, see Item 1A of our 2010 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. [Removed and Reserved]

Item 5. Other Information

None.

Item 6. Exhibits

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	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).
3.4	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	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).

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10.2	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).
10.3	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).
10.4	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 on August 25, 2011).
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.
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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.

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SIGNATURES

Pursuant to the requirements 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: November 4, 2011 By: /s/ GREG L. ARMSTRONG

Name: Greg L. Armstrong
Title: Chairman and Chief Executive Officer
(Principal Executive Officer)

Date: November 4, 2011 By: /s/ DEAN LIOLLIO

Name: Dean Liollio
Title: President

Date: November 4, 2011 By: /s/ AL SWANSON

Name: Al Swanson
Title: Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

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