PAA NATURAL GAS STORAGE LP
Form 10-Q
August 07, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2013

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 (State or other jurisdiction of incorporation or organization)	**27-1679071** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1500, Houston, Texas (Address of principal executive offices)	**77002** (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. x 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). x 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 x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of July 31, 2013, there were 61,147,449 common units outstanding.

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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

(in thousands, except units)

	June 30, 2013 (unaudited)	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 969	$ 650
Trade accounts receivable and other receivables, net	29,040	25,993
Natural gas inventory	48,013	59,685
Other current assets	7,565	8,065
Total current assets	85,587	94,393
PROPERTY AND EQUIPMENT	1,381,535	1,363,525
Accumulated depreciation, depletion and amortization	(60,032)	(49,607)
	1,321,503	1,313,918
OTHER ASSETS		
Base gas	58,297	54,091
Goodwill	325,470	325,470
Intangibles and other assets, net	71,861	81,197
Total other assets, net	455,628	460,758
Total assets	$ 1,862,718	$ 1,869,069
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 34,149	$ 27,621
Short-term debt	48,772	76,715
Total current liabilities	82,921	104,336
LONG-TERM LIABILITIES		
Note payable to PAA	200,000	200,000
Long-term debt under credit agreement	296,928	305,385
Other long-term liabilities	8,705	8,406
Total long-term liabilities	505,633	513,791
Total liabilities	588,554	618,127
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS CAPITAL		
Common unitholders (60,644,397 units issued and outstanding at June 30, 2013)	1,030,921	1,013,848
Subordinated unitholders (25,434,351 units issued and outstanding at June 30, 2013)	222,092	225,123

General partner		29,607		28,737
Accumulated other comprehensive income/(loss)		(8,456)		(16,766)
Total partners capital		1,274,164		1,250,942
Total liabilities and partners capital	$	1,862,718	$	1,869,069

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

(in thousands, except per unit data)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(unaudited)		(unaudited)	
REVENUES				
Firm storage services	$ 35,096	$ 35,475	$ 71,557	$ 69,282
Hub services	1,452	2,336	4,002	5,472
Natural gas sales	77,148	62,000	164,942	132,620
Other	1,862	330	3,990	1,489
Total revenues	115,558	100,141	244,491	208,863
COSTS AND EXPENSES				
Storage-related costs	2,786	4,329	8,137	11,020
Natural gas sales costs	74,712	60,181	159,172	127,345
Field operating costs	3,863	3,009	7,253	6,056
General and administrative expenses	5,034	4,616	10,754	9,663
Depreciation, depletion and amortization	9,845	9,318	19,484	18,394
Total costs and expenses	96,240	81,453	204,800	172,478
OPERATING INCOME	19,318	18,688	39,691	36,385
OTHER INCOME/(EXPENSE)				
Interest expense (net of capitalized interest of $885, $2,118, $2,155 and $4,521, respectively)	(2,730)	(1,709)	(5,128)	(3,377)
Other income/(expense), net	(9)	28	(15)	17
NET INCOME	$ 16,579	$ 17,007	$ 34,548	$ 33,025
NET INCOME AVAILABLE TO LIMITED PARTNERS	$ 16,020	$ 16,449	$ 33,412	$ 31,929
NET INCOME PER LIMITED PARTNER UNIT				
Common and Series A subordinated units(1) (Basic)	$ 0.22	$ 0.23	$ 0.46	$ 0.45
Common and Series A subordinated units(1) (Diluted)	$ 0.22	$ 0.23	$ 0.46	$ 0.45
WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING				
Common and Series A subordinated units(1) (Basic)	72,418	71,128	71,784	71,128
Common and Series A subordinated units(1) (Diluted)	72,688	71,252	72,041	71,245

(1) Excludes Series B subordinated units. See Note 7, 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 Statements of Comprehensive Income

(in thousands)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(unaudited)		(unaudited)	
Net income	$ 16,579	$ 17,007	$ 34,548	$ 33,025
Other comprehensive income/(loss)	16,311	(5,356)	8,310	(15,044)
Comprehensive income	$ 32,890	$ 11,651	$ 42,858	$ 17,981

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income/(Loss)

(in thousands)

	Total (unaudited)
Balance, December 31, 2012	$ (16,766)
Reclassification adjustments	13,114
Deferred gain/(loss) on cash flow hedges, net	(4,804)
Total period activity	8,310
Balance, June 30, 2013	$ (8,456)

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

(in thousands)

	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
	(unaudited)			
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$	34,548	$	33,025
Reconciliation of net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		19,484		18,394
Equity-indexed compensation expense		3,530		2,372
Unrealized (gain)/loss on derivative instruments		191		556
Change in assets and liabilities:				
Trade accounts receivable and other		4,077		(3,172)
Natural gas inventory		15,949		2,652
Accounts payable and other liabilities		3,566		(11,581)
Net cash provided by operating activities		81,345		42,246
CASH FLOWS FROM INVESTING ACTIVITIES				
Additions to property and equipment		(16,897)		(31,096)
Net cash received/(paid) for sales and purchases of base gas		(5,557)		4,295
Other investing activities				62
Net cash used in investing activities		(22,454)		(26,739)
CASH FLOWS FROM FINANCING ACTIVITIES				
Net short-term borrowings/(repayments) under credit agreement		(27,942)		12,173
Net long-term borrowings/(repayments) under credit agreement		(8,458)		25,127
Net proceeds from the issuance of common units		30,469		
Costs incurred in connection with financing arrangements		(10)		(305)
Contributions from general partner		624		
Distributions paid to unitholders		(51,320)		(50,857)
Distributions paid to general partner		(1,496)		(1,482)
Distribution equivalent right payments		(439)		(165)
Net cash provided by/(used in) financing activities		(58,572)		(15,509)
Net increase/(decrease) in cash and cash equivalents		319		(2)
Cash and cash equivalents, beginning of period		650		496
Cash and cash equivalents, end of period	$	969	$	494
Cash paid for:				
Interest, net of amounts capitalized	$	5,875	$	3,973
Income taxes, net of amounts refunded	$	96	$	
Non-cash items				
Increase/(decrease) in accrued capital expenditures	$	1,114	$	(1,916)

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

(in thousands)

	Partners Capital Limited Partners Common	Subordinated Series A	Series B	General Partner	Accumulated Other Comprehensive Income/(Loss)	Total
Balance at December 31, 2012	**$ 1,013,848**	**$ 123,332**	**$ 101,791**	**$ 28,737**	**$ (16,766)**	**$ 1,250,942**
Net income	27,910	5,502		1,136		34,548
Equity-indexed compensation expense	2,103			606		2,709
Distributions to unitholders and general partner	(42,787)	(8,533)		(1,496)		(52,816)
Distribution equivalent rights paid or accrued	(315)					(315)
Issuance of common units, net of offering costs	30,162			624		30,786
Change in deferred gain/(loss) on cash flow hedges, net					8,310	8,310
Balance at June 30, 2013	**$ 1,030,921**	**$ 120,301**	**$ 101,791**	**$ 29,607**	**$ (8,456)**	**$ 1,274,164**

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)

Note 1 Organization 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 June 30, 2013, through these facilities, PNG had a total of nine operational salt storage caverns and two depleted reservoirs used for natural gas storage, with an aggregate owned working gas storage capacity of approximately 97 billion cubic feet (Bcf). We also own PNG Marketing, LLC, a wholly owned commercial optimization company that captures short-term market opportunities by leasing a portion of our storage capacity and engaging in related commercial marketing activities.

As of June 30, 2013, PAA owned approximately 63% of the equity interests in the Partnership, including our 2.0% general partner interest and limited partner interests consisting of 28,155,526 common units, 11,934,351 Series A subordinated units and 13,500,000 Series B subordinated units.

The 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 2012 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, 2012 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 six months ended June 30, 2013 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, unless the context indicates otherwise.

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2012 Annual Report on Form 10-K, no new accounting pronouncements have become effective or have been issued during the six months ended June 30, 2013 that are of significance or potential significance to us.

In February 2013, the FASB issued guidance requiring an entity to present either in a single note or parenthetically on the face of the financial statements (i) the amount of significant items reclassified from each component of accumulated other comprehensive income (AOCI) and (ii) the income statement line items affected by the reclassification. This guidance became effective for interim and annual periods beginning after December 15, 2012. We adopted this guidance during the first quarter of 2013. During the three and six months ended June 30, 2013 and 2012, all reclassifications out of AOCI were related to derivative instruments. Other than requiring disclosure, which is included in Note 10, our adoption did not have an impact on our financial position, results of operations or cash flows.

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We adopted this guidance on January 1, 2013. Our adoption did not have an impact on our financial position, results of operations or cash flows.

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In December 2011, the FASB issued guidance requiring disclosures of both gross and net information about recognized financial instruments and derivative instruments that are either (i) offset in accordance with the specified sections of GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement. In January 2013, the FASB amended and clarified the scope of these disclosures to include only (i) derivative instruments, (ii) repurchase agreements and reverse repurchase agreements and (iii) securities lending transactions. Other than requiring additional disclosure, which is included in Note 10, our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3 Accounts Receivable

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At June 30, 2013 and December 31, 2012, substantially all of our accounts receivable were current and we had no allowance for doubtful accounts.

Our accounts receivable are from a broad mix of customers, including local gas distribution companies, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers and affiliates of such entities.

To mitigate credit risk related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require, in each case acting in accordance with the provisions of the credit terms and provisions set forth in our Federal Energy Regulatory Commission (FERC) approved tariffs, where applicable. Such financial assurances are commonly provided to us in the form of standby letters of credit, parental guarantees or advance cash payments. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables against each other) that cover substantially all of our natural gas purchases and sales transactions and also serve to mitigate credit risk.

Note 4 Inventory and Base Gas

Inventory and base gas consisted of the following (natural gas volumes in thousands and carrying values in thousands):

	As of June 30, 2013			As of December 31, 2012		
	Volumes	Unit of Measure	Carrying Value (1)	Volumes	Unit of Measure	Carrying Value (1)
Inventory						
Natural gas (2)(3)(4)	13,341	Mcf	$ 48,013	20,374	Mcf	$ 59,685
Base Gas						
Natural gas (5)(6)	16,965	Mcf	58,297	15,755	Mcf	54,091
Total			$ 106,310			$ 113,776

(1) Carrying value represents a weighted-average associated with various locations; accordingly, these values may not coincide with any published benchmarks for such products.

(2) Includes fuel inventory held for operational purposes.

(3) As of December 31, 2012, the carrying value of natural gas inventory reflects lower of cost or market adjustments of approximately $4.3 million. No lower of cost or market adjustments were included in the carrying value of natural gas inventory as of June 30, 2013. Lower of cost or market adjustments are reflected as a component of natural gas sales costs in our condensed consolidated statement of operations. The impacts of such adjustments are generally offset by the recognition of unrealized gains on derivative instruments being utilized to hedge the future sales of our natural gas inventory.

(4) Natural gas inventory balances exclude derivative gains and losses associated with settled derivatives that were entered into to hedge natural gas inventory purchases. As of June 30, 2013, net deferred gains of approximately $2.4 million associated with settled derivatives are reflected as a component of accumulated other comprehensive income/(loss) in our condensed consolidated balance sheet. Such amounts will be reclassified to earnings in conjunction with an earnings impact associated with the applicable purchase of inventory (typically when such inventory is sold).

(5) As of June 30, 2013, we had outstanding loan agreements against base gas totaling approximately 11.6 Bcf of natural gas, the majority of which is scheduled to be returned to us by November 30, 2013 in accordance with the terms of the agreements.

(6) During the quarter ended June 30, 2013, we purchased approximately 1.0 Bcf of additional base gas. Net cash payments of approximately $1.4 million were made during the quarter ended June 30, 2013 associated with the settlement of derivatives hedging base gas purchases. Such amounts are reflected as a component of accumulated other comprehensive income/(loss) in our condensed consolidated balance sheet as of June 30, 2013.

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Note 5 Goodwill

The table below reflects our changes in goodwill for the period indicated (in thousands):

		Total
Balance, December 31, 2012	$	325,470
2013 Goodwill Related Activity:		
Acquisitions		
Purchase price accounting adjustments and other		
Balance, June 30, 2013	$	325,470

Note 6 Debt

Debt consisted of the following as of the dates indicated (in thousands):

		As of June 30, 2013		As of December 31, 2012
Short-Term Debt				
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at June 30, 2013 and December 31, 2012, respectively (1)(2)	$	48,772	$	76,715
Total short-term debt		48,772		76,715
Long-Term Debt				
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at June 30, 2013 and December 31, 2012, respectively (1)(2)		96,928		105,385
GO Bond Term Loans, bearing a weighted-average interest rate of 1.5% at both June 30, 2013 and December 31, 2012, respectively (2)		200,000		200,000
Promissory note due to PAA bearing interest of 4.0% at both June 30, 2013 and December 31, 2012 (2)		200,000		200,000
Total long-term debt		496,928		505,385
Total debt (1)(2)	$	545,700	$	582,100

(1) We classify as short-term debt any borrowings under our senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of our funded hedged natural gas inventory (which includes the impact of cash settled derivative positions associated with owned inventory) and NYMEX margin requirements. Approximately $0.4 million and $0.7 million of interest expense attributable to such borrowings is reflected as a component of natural gas sales costs in the condensed consolidated statements of operations for the three and six months ended June 30, 2013, respectively; and approximately $0.3 million and $0.5 million for the three and six months ended June 30, 2012, respectively.

(2) We estimate that the fair value of borrowings outstanding under our credit agreement (including the revolving credit facility and GO Bond Term Loans) and the PAA Promissory Note approximate carrying value due to the short maturity of both obligations and the variable interest rate terms set forth under our credit agreement. Our fair value estimate for amounts outstanding under our credit agreement is based upon observable market data and is classified within Level 2 of the fair value hierarchy. With regard to the PAA Promissory Note, our fair

valuation estimation process incorporates our estimated credit spread, an unobservable input. As such, we consider this to be a Level 3 measurement within the fair value hierarchy.

Our revolving credit facility includes the ability to issue letters of credit. As of June 30, 2013, we had approximately $10,000 of outstanding letters of credit under our revolving credit facility.

Total borrowings under our credit agreement for the six months ended June 30, 2013 and 2012 were approximately $230.4 million and $148.5 million, respectively. Total repayments under our credit agreement were approximately $266.8 million and $111.2 million for the six months ended June 30, 2013 and 2012, respectively.

As of June 30, 2013, we were in compliance with the covenants required by our credit agreement.

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Interest payments on the PAA Promissory Note are paid semiannually on the last business day of June and December. Interest paid to PAA during the six months ended June 30, 2013 was approximately $4.0 million. There was no accrued interest payable due under the PAA Promissory Note as of June 30, 2013 or December 31, 2012.

Note 7 Net Income per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined pursuant to the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, limited partner unit holders and participating securities according to distributions pertaining to the current period s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our general partner, limited partner unit holders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

The Partnership calculates basic and diluted net income per limited partner unit by dividing net income, after deducting the amount allocated to the general partner s interest, incentive distribution rights (IDRs) and participating securities, by the basic and diluted weighted-average number of limited partner units outstanding during the period. Participating securities include LTIP awards that have vested distribution equivalent rights (DERs), which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income per limited partner unit is computed based on the weighted-average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

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The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2013 and 2012 (amounts in thousands, except per unit data):

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income	$ 16,579	$ 17,007	$ 34,548	$ 33,025
General partner s incentive distribution	(232)	(222)	(454)	(444)
General partner s 2% ownership interest	(327)	(336)	(682)	(652)
Net income available to limited partners	16,020	16,449	33,412	31,929
Undistributed earnings allocated and distributions to participating securities (1)	(149)	(83)	(315)	(165)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 15,871	$ 16,366	$ 33,097	$ 31,764
Numerator for basic and diluted earnings per limited partner unit:				
Allocation of net income amongst limited partner interests:				
Net income allocable to common units	$ 13,255	$ 13,620	$ 27,594	$ 26,435
Net income allocable to Series A subordinated units	2,616	2,746	5,503	5,329
Net income allocable to Series B subordinated units (2)				
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 15,871	$ 16,366	$ 33,097	$ 31,764
Denominator:				
Basic weighted average number of limited partner units outstanding: (2)(3)(4)				
Common units	60,484	59,194	59,850	59,194
Series A subordinated units	11,934	11,934	11,934	11,934
Series B subordinated units	13,500	13,500	13,500	13,500
Diluted weighted average number of limited partner units outstanding: (2)(3)(4)				
Common units	60,754	59,318	60,107	59,311
Series A subordinated units	11,934	11,934	11,934	11,934
Series B subordinated units	13,500	13,500	13,500	13,500
Basic and diluted net income per limited partner unit: (2)(3)(4)				
Common units	$ 0.22	$ 0.23	$ 0.46	$ 0.45
Series A subordinated units	$ 0.22	$ 0.23	$ 0.46	$ 0.45
Series B subordinated units	$	$	$	$

(1) Participating securities consist of LTIP awards (see Note 9) containing vested distribution equivalent rights which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

(2) 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.

(3) The determination of diluted weighted average units outstanding includes the impact of equity-classified LTIP awards which vest based solely on the passage of time. Equity-classified LTIP awards which contain provisions whereby vesting occurs only upon the satisfaction of a performance condition, which have not been satisfied during the periods presented, are excluded from the determination of diluted weighted average units outstanding.

(4) The conversion of (i) our Series A subordinated units to common units and (ii) our Series B subordinated units to Series A subordinated units or common units is subject to certain performance conditions. None of these performance conditions had been satisfied as of June 30, 2013 therefore, there is no dilutive impact of such units in our determination of diluted net income per limited partner unit.

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Note 8 Partners Capital and Distributions

Outstanding Units

From December 31, 2012 through June 30, 2013, changes in our issued and outstanding common, Series A subordinated or Series B subordinated units were as follows:

		Subordinated		
	Common	Series A	Series B	Total
Balance, December 31, 2012	59,205,075	11,934,351	13,500,000	84,639,426
Issuance of common units	1,439,322			1,439,322
Balance, June 30, 2013	60,644,397	11,934,351	13,500,000	86,078,748

Distributions

The following table details the distributions on our common and Series A subordinated units declared for 2013 quarterly periods or paid during the six months ended June 30, 2013 (in thousands, except per unit amounts):

		Distributions Paid					
				General Partner			
Date Declared	Date Paid or To Be Paid	Common Units	Series A Subordinated Units	Incentive	2%	Total	Distribution per unit
July 8, 2013	August 14, 2013 (1)	$ 21,860	$ 4,267	$ 258	$ 503	$ 26,888	$ 0.3575
April 8, 2013	May 15, 2013	$ 21,621	$ 4,267	$ 255	$ 499	$ 26,642	$ 0.3575
January 7, 2013	February 14, 2013	$ 21,165	$ 4,267	$ 251	$ 491	$ 26,174	$ 0.3575

(1) Payable to unitholders of record on August 2, 2013, for the period April 1, 2013 through June 30, 2013.

Equity Offerings

During the first quarter of 2013, we entered into an equity distribution agreement with a financial institution pursuant to which we may offer and sell, through this financial institution as our sales agent, common units representing limited partner interests having an aggregate offering price of up to $75 million. Sales of such common units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by our sales agent and us. Under the terms of the agreement, we have the option to sell common units to our sales agent as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, we will enter into a separate terms agreement with the sales agent. Through the second quarter of 2013, we issued an aggregate of 1.4 million common units under this agreement, generating net proceeds of approximately $30.8 million, including our general partner s proportionate capital contribution.

Note 9 Equity-Indexed Compensation

Long-Term Incentive Plan (LTIP)

For discussion of our equity-indexed compensation awards, see Note 13 to our consolidated financial statements included in Part IV of our 2012 Annual Report on Form 10-K.

Awards Granted Under the 2010 LTIP Plan

In February 2013, approximately 300,000 equity-classified phantom units were granted under the 2010 LTIP Plan. Such awards will vest in one-third tranches on the dates we pay annualized distributions of $1.45, $1.50 and $1.55. Fifty percent of any unvested phantom units in a particular tranche that remain outstanding as of the August 2016, 2017 and 2018 distribution dates will vest on such date and the remaining portion of such tranche and all associated DERs will be forfeited as of the August 2019 distribution date if the applicable performance conditions for such tranche have not been met by such date. DERs associated with these awards will vest in one-third increments on the August 2014, 2015 and 2016 distribution dates, provided that our quarterly distribution remains at least $1.43 (annualized) per unit.

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In January 2013, approximately 100,000 awards were granted under the 2010 LTIP Plan. Approximately 70,000 of the awards will vest as follows: (i) one-third will vest upon the August 2015 distribution date; (ii) one-third will vest upon the August 2016 distribution date; and (iii) one-third will vest upon the later of the August 2017 distribution date and the date we pay a $1.48 annualized distribution. In addition, 100% of any unvested awards that remain outstanding upon the August 2018 distribution date shall vest. The other approximately 30,000 awards will vest upon the August 2016 distribution date. Of the approximately 100,000 awards granted, approximately 60,000 awards are liability-classified and approximately 40,000 awards are equity-classified.

Special PAA Awards

In February 2013, PAA granted 143,000 Special PAA awards to certain members of our management. These awards are denominated in units of PAA, and will vest 50% on PAA s August 2018 distribution date and 50% on PAA s August 2019 distribution date provided that PNG s annualized distribution averages at least $1.48 and $1.43 per unit, respectively, for the twelve months prior to each vesting date. DERs associated with these awards will vest on the date PAA pays an annualized distribution of $2.40 per unit, provided that PNG s quarterly distribution remains at least $1.43 (annualized) per unit. Any unvested Special PAA awards that remain outstanding on December 31, 2020 will be forfeited. The entire economic burden of these awards will be borne solely by PAA and will not impact our cash or units outstanding. As the recipients of these awards serve as officers of PNG and we benefit from the services they provide, we will recognize the fair value of these awards as compensation expense over the service period, with such expense recognized as a capital contribution. These awards were granted in conjunction with cancellation of the PNGS Class B Units which were terminated in February 2013.

Consolidated Equity-Indexed Compensation Information

Our equity-indexed compensation activity for awards denominated in PNG units issued under the 2010 LTIP Plan is summarized in the following table (units in thousands):

	Units (1)		**Weighted Average Grant Date Fair Value per Unit**
Outstanding, December 31, 2012	619	$	15.75
Granted	440	$	17.34
Vested	(13)	$	14.77
Cancelled or forfeited	(40)	$	14.40
Outstanding, June 30, 2013 (2)	1,006	$	16.51

(1) Amounts do not include Special PAA awards or transaction awards granted by PAA.

(2) Includes approximately 850,000 equity-classified awards and 156,000 liability-classified awards.

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The tables below summarize the expense recognized and cash settled vestings related to equity-indexed compensation awards during the three and six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30, 2013		Six Months Ended June 30, 2013	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity-indexed compensation expense (1)(2)	$ 293	$ 1,444	$ 821	$ 2,709
LTIP cash settled vestings (3)	$ 1,204	$	$ 1,204	$
Distribution equivalent right payments	$ 5	$ 149	$ 9	$ 439

	Three Months Ended June 30, 2012		Six Months Ended June 30, 2012	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity-indexed compensation expense (1)(2)	$ 151	$ 1,081	$ 289	$ 2,083
LTIP cash settled vestings (3)	$ 636	$	$ 740	$
Distribution equivalent right payments	$ 6	$ 83	$ 12	$ 165

(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. The individuals that received these awards are officers of PAA and PNG, and because they 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 $0.2 million and $0.4 million of compensation expense associated with these equity-classified awards during the three and six months ended June 30, 2013, respectively; and approximately $0.3 million and $0.8 million for the three and six months ended June 30, 2012, respectively.

(2) Includes expense associated with Special PAA awards granted by PAA in February 2013. The entire economic burden of these awards will be borne solely by PAA and will not impact our cash or units outstanding. We recognized approximately $0.1 million and $0.2 million of compensation expense associated with these equity-classified awards during the three and six months ended June 30, 2013, respectively.

(3) Includes cash payments made in conjunction with the settlement of PAA common unit denominated LTIP awards.

Note 10 Derivatives 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 risk management strategies utilize various derivatives to manage our exposure to both commodity price risk and interest rate risk. When we apply hedge accounting, at the inception of a hedge we formally document the relationship between the hedging instrument and the hedged item, as well as our risk management objective for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives within the hedging relationship are highly effective in offsetting changes in cash flows of hedged items. Our policy is to use derivatives only for hedging purposes and not for the purpose of speculating.

Commodity Price Risk Hedging

We utilize derivatives to manage exposure associated with commodity price risk (resulting from natural gas price fluctuations in spot and forward markets, among other factors) and to optimize profits as follows:

Merchant Storage Activities- When contango market conditions exist (forward prices exceed spot prices), our commercial optimization company may utilize our storage capacity to purchase natural gas and hold it for sale at a higher price in a forward month. Additionally, our commercial optimization company may sell owned natural gas inventory in the current month and repurchase it at a lower price in a forward month when backwardated market conditions exist (spot prices exceed forward prices).

In conjunction with our merchant storage activities, we typically enter into a spread position to hedge both purchases and sales of natural gas in the respective months. The hedging instrument for each respective month is settled concurrent with the applicable

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physical transaction. This enables us to maintain a balanced position when our hedging instruments are aggregated with physical purchases and sales. The fair value of our derivative spread positions is exposed to changes in the spread (the price difference between two distinct months). However, the fair value of our derivative spread positions is not exposed to changes in outright prices and is offset by the corresponding change in fair value of the physical position that is being hedged.

Operational Gas Purchases and Sales- We purchase and sell natural gas for operational purposes at our storage facilities. These activities primarily consist of the purchase of base gas for caverns under development or anticipated future development of our facilities. We also sell surplus fuel inventory, which we collect from our customers under the terms of our storage contracts. We use derivatives to manage the commodity price risk associated with all, or a portion of, these anticipated purchases of base gas and sales of fuel inventory.

Crude Oil Sales- We sell crude oil and liquids produced in conjunction with the operation of our Bluewater facility. We may use derivatives to manage the commodity price risk associated with a portion of these anticipated sales.

Storage Capacity Utilization- The fair value of our storage capacity is partially derived from the seasonal spread in forward natural gas prices. We may from time to time use derivatives to hedge our exposure associated with available capacity.

The risk management strategies we utilize to manage commodity price risk exposure associated with these core activities include the use of exchange-cleared futures (including basis and index futures) and options. The following table summarizes open derivative positions utilized in commodity price risk management strategies as of June 30, 2013:

	Notional Volume (Short)/Long (1)	**Remaining Tenor (1)**
Anticipated net base gas purchases	1.9 Bcf	April 2016
Anticipated natural gas sales of owned inventory (2)	(13.3) Bcf	December 2013
Anticipated natural gas inventory purchases	5.6 Bcf	November 2014
Anticipated natural gas inventory sales (3)	(5.0) Bcf	April 2014
Anticipated sales of crude oil	(6,000) bbls	December 2013

(1) Volumes presented represent the aggregate position through the month noted.

(2) Notional volumes presented hedge forecasted sales of natural gas inventory owned as of June 30, 2013.

(3) Notional volumes presented hedge forecasted sales of anticipated future natural gas purchases.

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 a total of 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

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

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A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2013, is as follows (in thousands):

	Three Months Ended June 30, 2013			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(Loss) reclassified from AOCI into income (effective portion) (1)	Gain/(Loss) recognized directly into income (ineffective portion)	Derivatives not designated as a hedge (2)	Total
Commodity Derivatives:				
Natural gas sales	$ (8,753)	$ 180	$ (377)	$ (8,950)
Other revenues	(4)			(4)
Interest Rate Derivatives:				
Interest expense	(168)			(168)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (8,925)	$ 180	$ (377)	$ (9,122)

	Six Months Ended June 30, 2013			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(Loss) reclassified from AOCI into income (effective portion) (1)	Gain/(Loss) recognized directly into income (ineffective portion)	Derivatives not designated as a hedge (2)	Total
Commodity Derivatives:				
Natural gas sales	$ (12,764)	$ (107)	$ (476)	$ (13,347)
Other revenues	(18)			(18)
Interest Rate Derivatives:				
Interest expense	(332)			(332)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ (13,114)	$ (107)	$ (476)	$ (13,697)

A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2012 is as follows (in thousands):

	Three Months Ended June 30, 2012			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(Loss) reclassified from AOCI into income (effective portion) (1)	Gain/(Loss) recognized directly into income (ineffective portion)	Derivatives not designated as a hedge (2)	Total
Commodity Derivatives:				
Natural gas sales	$ 2,153	$ 252	$	$ 2,405
Other revenues	(92)		(793)	(885)
Interest Rate Derivatives:				
Interest expense	(117)			(117)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 1,944	$ 252	$ (793)	$ 1,403

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	Six Months Ended June 30, 2012			
	Derivatives in Hedging Relationships			
Location of gain/(loss)	Gain/(Loss) reclassified from AOCI into income (effective portion) (1)	Gain/(Loss) recognized directly into income (ineffective portion)	Derivatives not designated as a hedge (2)	Total
Commodity Derivatives:				
Natural gas sales	$ 13,745	$ 71	$ 163	$ 13,979
Natural gas sales costs (3)	3,877			3,877
Other revenues	(172)		(626)	(798)
Interest Rate Derivatives:				
Interest expense	(221)			(221)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 17,229	$ 71	$ (463)	$ 16,837

(1) During the three and six months ended June 30, 2013, we reclassified gains of approximately $1.1 million from AOCI to natural gas sales revenues as a result of anticipated hedged transactions that are probable of not occurring. Additionally, during the three and six months ended June 30, 2012, we reclassified gains of approximately $0.4 million and $0.5 million, respectively, as a result of anticipated hedged transactions that are probable of not occurring.

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

(3) Amounts reported as a component of natural gas sales costs in our condensed consolidated statements of operations reflect reclassifications from AOCI to earnings to offset applicable lower of cost or market adjustments to the carrying value of our inventory.

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of June 30, 2013 (in thousands):

	As of June 30, 2013			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 2,500	Other current assets	$ (844)
	Other long-term liabilities	55	Other long-term liabilities	(555)
Interest rate derivatives			Other current liabilities	(546)
			Other long-term liabilities	(40)
Total derivatives designated as hedging instruments		$ 2,555		$ (1,985)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 1,051	Other current assets	$ (838)
			Other current liabilities	(18)
Total derivatives not designated as hedging instruments		$ 1,051		$ (856)

Total derivatives	$	3,606	$	(2,841)

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The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2012 (in thousands):

	As of December 31, 2012						
	Asset Derivatives			Liability Derivatives			
	Balance Sheet Location	Fair Value		Balance Sheet Location	Fair Value		
Derivatives designated as hedging instruments:							
Commodity derivatives	Other current assets	$	10,556	Other current assets	$	(3,143)	
	Other long-term assets		310	Other long-term assets			
Interest rate derivatives				Other current liabilities		(554)	
				Other long-term liabilities		(304)	
Total derivatives designated as hedging instruments		$	10,866		$	(4,001)	
Derivatives not designated as hedging instruments:							
Commodity derivatives	Other current assets	$	5	Other current assets	$	(8)	
Total derivatives not designated as hedging instruments		$	5		$	(8)	
Total derivatives		$	10,871		$	(4,009)	

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on our performance obligations, thus causing an early termination event. If such an event would occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our commodity derivatives, which are all exchange-cleared, are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or receipt of variation margin. As of June 30, 2013 and December 31, 2012, we had a net broker receivable of approximately $2.2 million (consisting of initial margin of $3.2 million decreased by $1.0 million of variation margin returned to us) and a net broker payable of approximately $2.4 million, respectively. Our interest rate derivatives, which are over-the-counter instruments, do not have margin requirements. At June 30, 2013 and December 31, 2012, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit standing. Although we may be required to post margin on our exchange-cleared derivatives, we do not require our over-the-counter derivative counterparties to post collateral with us.

The following tables present information about derivative related assets and liabilities that are subject to offsetting, including enforceable master netting arrangements at June 30, 2013 and December 31, 2012 (in thousands):

	June 30, 2013		December 31, 2012	
	Asset Positions	Liability Positions	Asset Positions	Liability Positions

Netting Adjustments:				
Gross position - asset/(liability)	$ 3,606	$ (2,841)	$ 10,871	$ (4,009)
Netting adjustment	(1,737)	1,737	(3,151)	3,151
Cash collateral paid/(received)	2,195		(2,395)	
Net position - asset/(liability)	$ 4,064	$ (1,104)	$ 5,325	$ (858)
Balance Sheet Location After Netting Adjustments:				
Other current assets	$ 4,064		$ 5,015	
Other long-term assets			310	
Other current liabilities		$ (546)		$ (553)
Other long-term liabilities		(558)		(305)
	$ 4,064	$ (1,104)	$ 5,325	$ (858)

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Accumulated Other Comprehensive Income

As of June 30, 2013, there was a net loss of approximately $8.5 million deferred in AOCI. Amounts deferred in AOCI include amounts associated with settled derivatives for which the underlying anticipated hedge transactions are still probable of occurring. The deferred loss in AOCI is expected to be reclassified to future earnings contemporaneously with the earnings recognition of the underlying hedged transactions. Certain underlying hedged transactions are for base gas purchases or other capital expansion expenditures. As we account for base gas as a long-term asset, which is not subject to depreciation, amounts related to base gas will not be reclassified to future earnings until such gas is sold or in the event an impairment charge is recognized in the future. Amounts related to other capital expansion activities will be reclassified to future earnings over the estimated useful life of the applicable asset. Deferred losses associated with capital expansion activities of approximately $11.6 million (including $9.3 million associated with base gas and anticipated base gas purchases) are included in AOCI as of June 30, 2013. Of the total net loss deferred in AOCI at June 30, 2013, we expect to reclassify a net gain of approximately $3.8 million to earnings in the next twelve months. Excluding amounts associated with capital activities, the remaining net loss will be reclassified to earnings through 2014. Amounts deferred related to open derivative positions are predominately based on market prices at the current period end, thus actual amounts to be reclassified related to those positions may differ and could vary materially as a result of changes in market conditions.

Amounts recognized in AOCI for derivatives and amounts reclassified to earnings during the three and six months ended June 30, 2013 and 2012 are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Commodity derivatives, net (1)	$ 7,419	$ (3,223)	$ (4,744)	$ 2,748
Interest rate derivatives, net (1)	(33)	(178)	(60)	(562)
Reclassification adjustments, net (2)	8,925	(1,945)	13,114	(17,230)
Total	$ 16,311	$ (5,346)	$ 8,310	$ (15,044)

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

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

Recurring Fair Value Measurements

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels. The determination of the fair values includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives and interest-rate derivatives includes adjustments for credit risk. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period.

Set forth in the table below is the Level 1 through Level 3 fair value hierarchy of our financial assets and liabilities that are accounted for at fair value on a recurring basis as of June 30, 2013 and December 31, 2012, respectively (in thousands):

	Fair Value as of June 30, 2013				Fair Value as of December 31, 2012			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 1,351	$	$	$ 1,351	$ 7,720	$	$	$ 7,720
Interest rate derivatives		(586)		(586)		(858)		(858)
Total	$ 1,351	$ (586)	$	$ 765	$ 7,720	$ (858)	$	$ 6,862

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

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Note 11 Commitments and Contingencies

Property Tax Matter

In December 2011, we received property tax bills from Evangeline Parish, Louisiana totaling approximately $1.5 million that assessed property taxes on property that we lease and maintain is exempt from property tax pursuant to a 2006 tax abatement arrangement. In order to properly protest such tax assessments under Louisiana law, we were required to pay the disputed taxes by December 31, 2011 and file suit within 30 days thereafter. We paid the taxes under protest in December 2011 and filed suit within the required 30 day period seeking recovery of the taxes based on the provisions of the tax abatement arrangement. In May 2012, approximately $1.4 million originally paid under protest was returned to us. Approximately $0.1 million remains under dispute.

In December 2012, Evangeline Parish issued additional property tax bills on the property subject to the 2006 tax abatement to us and Industrial Development Board No. 1 of the State of Louisiana, Inc, the lessor of the property, totaling approximately $1.3 million. We paid these taxes under protest in December 2012 and filed suit within the required 30 day period to protest these billings and seek recovery of the amounts paid under protest.

As of June 30, 2013, approximately $1.4 million of property taxes paid to Evangeline Parish under protest are reflected as a component of other current assets on our condensed consolidated balance sheet. We have not recognized any property tax expense related to these billings as they relate to property which we believe is exempt from taxes in accordance with the terms of the 2006 tax abatement agreement.

Note 12 Operating Segments

We manage our operations through three operating segments: (i) Pine Prairie, (ii) Southern Pines and (iii) Bluewater. We have aggregated these operating segments into one reporting segment, Natural Gas Storage, 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.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on measures including adjusted EBITDA and maintenance capital investment. We define adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity-indexed compensation plan charges, unrealized gains and losses from derivative activities and other adjustments for the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we refer to as selected items impacting comparability or selected items.

As a master limited partnership, we make quarterly distributions of our available cash (as defined in our partnership agreement) to our unitholders. We look at each period s adjusted EBITDA (which excludes depreciation, depletion and amortization expense) as an important measure of segment performance. The exclusion of depreciation and amortization expense related to our capital assets could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets caused by age-related decline and wear and tear. We compensate for this limitation by recognizing that age-related decline and wear and tear are largely offset by repair and maintenance investments. These maintenance investments are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining available cash, consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. Capital expenditures made to expand the existing earnings capacity of our assets are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues	$ 115,558	$ 100,141	$ 244,491	$ 208,863
Adjusted EBITDA	$ 30,586	$ 29,669	$ 62,139	$ 57,484
Maintenance capital expenditures	$ 67	$ 190	$ 217	$ 372

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

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Adjusted EBITDA	$ 30,586	$ 29,669	$ 62,139	$ 57,484
Selected items impacting adjusted EBITDA:				
Equity-indexed compensation expense (1)	(1,429)	(1,093)	(2,788)	(2,132)
Mark-to-market of open derivative positions	(3)	(542)	(191)	(556)
Depreciation, depletion and amortization	(9,845)	(9,318)	(19,484)	(18,394)
Interest expense, net of capitalized interest (2)	(2,730)	(1,709)	(5,128)	(3,377)
Net Income	$ 16,579	$ 17,007	$ 34,548	$ 33,025

(1) Excludes equity-indexed compensation expense attributable to certain awards which will be settled in cash upon vesting.

(2) Excludes interest expense attributable to our funded natural gas inventory (See Note 6).

Note 13 Related Party Transactions

In addition to transactions between PNG and PAA discussed in Notes 6, 8 and 9, additional activities between PNG and PAA are discussed below.

Total costs reimbursed by us to PAA for the three and six months ended June 30, 2013, were approximately $3.7 million, and $6.5 million, respectively; and approximately $4.1 million and $8.8 million for the three and six months ended June 30, 2012, respectively. Of these amounts, approximately $0.6 million, $1.5 million, $0.9 million and $1.8 million, during the three and six month periods ended June 30, 2013 and 2012, respectively, were allocated costs for shared services (including personnel costs) and the remainder consisted of reimbursements for direct operating and capital costs that PAA paid on our behalf.

As of June 30, 2013 and December 31, 2012, PNG had amounts due to PAA of approximately $0.6 million and $0.2 million, respectively, included in accounts payable and accrued liabilities on our condensed consolidated balance sheet. Such amounts include accrued interest, if any, due under the PAA Promissory Note (see Note 6) and exclude amounts related to the firm storage agreements with PAA discussed below.

As of June 30, 2013, outstanding parental guarantees issued by PAA to third parties on behalf of PNG Marketing were approximately $15 million. No amounts were due to PAA as of June 30, 2013 under such guarantees and no payments were made to PAA under such guarantees during the six months ended June 30, 2013. 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 six months ended June 30, 2013 and 2012, we incurred approximately $17,000, $29,000, $34,000 and $47,000 of expense, respectively, under our obligation to reimburse PAA for administrative costs incurred in conjunction with providing parental guarantees on our behalf.

Firm Storage Agreements with PAA

In the first quarter of 2013, our Pine Prairie subsidiary entered into two 10 Bcf firm storage agreements with PNG Marketing, and PNG Marketing agreed to release the capacity under such agreements to a subsidiary of PAA pursuant to applicable FERC rules and regulations. One of the agreements has a two year term that commenced on March 31, 2013 and the other has a three year term that started on the same date. The PAA subsidiary makes all required payments under the firm storage agreements directly to our Pine Prairie subsidiary. Excluding variable payments that depend on the use of the firm storage capacity, the total fixed payments required to be made by the applicable PAA subsidiary to our Pine Prairie subsidiary during the life of the two storage agreements is approximately $49 million. PNG Marketing manages the storage capacity on behalf of the PAA subsidiary on a cost reimbursement basis.

During the three and six months ended June 30, 2013, we recognized approximately $5.2 million of firm storage services revenue under these agreements. Additionally, during the six months ended June 30, 2013, we recognized approximately $13.7 million of natural gas sales revenues from the market-based sale of natural gas owned by PNG Marketing to the applicable subsidiary of PAA at the inception of these agreements. Subsequent inventory purchases (approximately $22.6 million during the three months ended June 30, 2013) and sales related to PNG Marketing s management of this storage capacity on a cost reimbursement basis have been accounted for on a net basis in our condensed consolidated statement of operations.

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Amounts due from such subsidiary of PAA under these agreements were approximately $15.5 million as of June 30, 2013. Such amounts are reflected in trade accounts receivable in our consolidated balance sheet.

Natural Gas Services Agreement

Access fee revenues under our Natural Gas Services Agreement with Plains Gas Solutions, LLC were approximately $0.4 million and $0.8 million, respectively, for the three and six months ended June 30, 2013; and $0.4 million and $0.8 million, respectively, for the three and six months ended June 30, 2012.

Natural Gas Sales

Revenues from sales of natural gas to Plains Gas Solutions, LLC were approximately $0.2 million for the six months ended June 30, 2012.

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.

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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 2012 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.

Overview of Operating Results, Capital Spending and Significant Activities

Adjusted EBITDA for the six months ended June 30, 2013 was approximately $62.1 million, an 8% increase over adjusted EBITDA of approximately $57.5 million for the six months ended June 30, 2012. This increase was primarily the result of incremental revenues attributable to working gas storage capacity expansions of approximately 4 Bcf in the aggregate at our Pine Prairie and Southern Pines facilities during 2013, sales of crude oil associated with liquids removal activities at our Bluewater facility and results of PNG Marketing, LLC (our commercial optimization company). See Results of Operations for further discussion and analysis of our operating results. Expansion capital expenditures for the six months ended June 30, 2013 were approximately $23.4 million.

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):

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	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Favorable/(Unfavorable) Variance(1) $	Favorable/(Unfavorable) Variance(1) %
Revenues				
Firm storage services	$ 35,096	$ 35,475	$ (379)	(1)%
Hub services and merchant storage(2)	78,600	64,336	14,264	22%
Other	1,862	330	1,532	464%
Total revenues	115,558	100,141	15,417	15%
Storage-related costs - Hub services and merchant storage(3)	(75,326)	(61,473)	(13,853)	(23)%
Storage-related costs - Firm storage services(4)	(2,172)	(3,037)	865	28%
Field operating costs	(3,863)	(3,009)	(854)	(28)%
General and administrative expenses	(5,034)	(4,616)	(418)	(9)%
Other income/(expense), net	(9)	28		
Equity-indexed compensation expense	1,429	1,093		
Mark-to-market of open derivative positions	3	542		
Adjusted EBITDA	$ 30,586	$ 29,669	$ 917	3%
Reconciliation to net income				
Adjusted EBITDA	$ 30,586	$ 29,669	$ 917	3%
Depreciation, depletion and amortization	(9,845)	(9,318)	(527)	(6)%
Interest expense, net of capitalized interest	(2,730)	(1,709)	(1,021)	(60)%
Equity-indexed compensation expense	(1,429)	(1,093)		
Mark-to-market of open derivative positions	(3)	(542)		
Net income	$ 16,579	$ 17,007	$ (428)	(3)%
Operating Data:				
Net revenue margin(5)	$ 38,063	$ 36,173	$ 1,890	5%
Field operating costs/ G&A/ Other	(7,477)	(6,504)	(973)	(15)%
Adjusted EBITDA	$ 30,586	$ 29,669	$ 917	3%
Average working storage capacity (Bcf)	97	80	17	21%
Monthly Operating Metrics ($/Mcf)				
Net revenue margin(5)	$ 0.13	$ 0.15	$ (0.02)	(13)%
Field operating costs/ G&A /Other	(0.03)	(0.03)		
Adjusted EBITDA	$ 0.10	$ 0.12	$ (0.02)	(17)%

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

(2) Includes revenues associated with sales of natural gas through commercial marketing activities.

(3) Includes costs associated with natural gas sold through commercial marketing activities and storage-related costs (including fuel expense) attributable to hub services and merchant storage revenues. Also includes interest expense attributable to our funded natural gas inventory. See Note 6 to our condensed consolidated financial statements for further discussion.

(4) Includes storage-related costs (including fuel expense) attributable to firm storage services revenues.

(5) Net revenue margin equals total revenues less storage-related costs and excludes the impact, if any, of mark-to-market adjustments (unrealized gains and losses) on open derivative positions.

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	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Favorable/(Unfavorable) Variance(1) $	Favorable/(Unfavorable) Variance(1) %
Revenues				
Firm storage services	$ 71,557	$ 69,282	$ 2,275	3%
Hub services and merchant storage(2)	168,944	138,092	30,852	22%
Other	3,990	1,489	2,501	168%
Total revenues	244,491	208,863	35,628	17%
Storage-related costs - Hub services and merchant storage(3)	(161,940)	(131,552)	(30,388)	(23)%
Storage-related costs - Firm storage services(4)	(5,369)	(6,813)	1,444	21%
Field operating costs	(7,253)	(6,056)	(1,197)	(20)%
General and administrative expenses	(10,754)	(9,663)	(1,091)	(11)%
Other income/(expense), net	(15)	17		
Equity-indexed compensation expense	2,788	2,132		
Mark-to-market of open derivative positions	191	556		
Adjusted EBITDA	$ 62,139	$ 57,484	$ 4,655	8%
Reconciliation to net income				
Adjusted EBITDA	$ 62,139	$ 57,484	$ 4,655	8%
Depreciation, depletion and amortization	(19,484)	(18,394)	(1,090)	(6)%
Interest expense, net of capitalized interest	(5,128)	(3,377)	(1,751)	(52)%
Equity-indexed compensation expense	(2,788)	(2,132)		
Mark-to-market of open derivative positions	(191)	(556)		
Net income	$ 34,548	$ 33,025	$ 1,523	5%
Operating Data:				
Net revenue margin(5)	$ 77,373	$ 71,054	$ 6,319	9%
Field operating costs/ G&A/ Other	(15,234)	(13,570)	(1,664)	(12)%
Adjusted EBITDA	$ 62,139	$ 57,484	$ 4,655	8%
Average working storage capacity (Bcf)	95	78	17	22%
Monthly Operating Metrics ($/Mcf)				
Net revenue margin(5)	$ 0.14	$ 0.15	$ (0.01)	(7)%
Field operating costs/ G&A /Other	(0.03)	(0.03)		
Adjusted EBITDA	$ 0.11	$ 0.12	$ (0.01)	(8)%

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

(2) Includes revenues associated with sales of natural gas through commercial marketing activities.

(3) Includes costs associated with natural gas sold through commercial marketing activities and storage-related costs (including fuel expense) attributable to hub services and merchant storage revenues. Also includes interest expense attributable to our funded natural gas inventory. See Note 6 to our condensed consolidated financial statements for further discussion.

(4) Includes storage-related costs (including fuel expense) attributable to firm storage services revenues.

(5) Net revenue margin equals total revenues less storage-related costs and excludes the impact, if any, of mark-to-market adjustments (unrealized gains and losses) on open derivative positions.

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

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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 measure as reported in accordance with GAAP, in the following table and should be viewed in addition to, and not in lieu of, our condensed consolidated financial statements and footnotes.

We define adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity-indexed 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 June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Adjusted EBITDA reconciliation				
Net income	$ 16,579	$ 17,007	$ 34,548	$ 33,025
Interest expense, net of capitalized interest (1)	2,730	1,709	5,128	3,377
Depreciation, depletion and amortization	9,845	9,318	19,484	18,394
Selected items impacting adjusted EBITDA				
Equity-indexed compensation expense (2)	1,429	1,093	2,788	2,132
Mark-to-market of open derivative positions	3	542	191	556
Adjusted EBITDA	**$ 30,586**	**$ 29,669**	**$ 62,139**	**$ 57,484**
Distributable cash flow reconciliation				
Net income	$ 16,579	$ 17,007	$ 34,548	$ 33,025
Depreciation, depletion and amortization	9,845	9,318	19,484	18,394
Maintenance capital expenditures	(67)	(190)	(217)	(372)
Other non cash items:				
Equity-indexed compensation expense, net of cash payments	379	508	1,878	1,454
Mark-to-market of open derivative positions	3	542	191	556
Distributable cash flow	**$ 26,739**	**$ 27,185**	**$ 55,884**	**$ 53,057**

(1) Excludes interest expense attributable to our funded natural gas inventory. See Note 6 to our condensed consolidated financial statements for further discussion.

(2) Excludes equity-indexed compensation expense attributable to certain awards which will be settled in cash upon vesting.

Three Months Ended June 30, 2013 as Compared to the Three Months Ended June 30, 2012

Revenues, Volumes and Related Costs. As noted in the table above, our total revenues net of storage-related costs increased during the three months ended June 30, 2013 (the 2013 period) when compared to the three months ended June 30, 2012 (the 2012 period). The primary reasons for such increase are incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities, the results of PNG Marketing, LLC (our commercial optimization company) and an increase in crude oil sales associated with liquids removal activities at our Bluewater facility. These and other significant variances related to these periods are discussed in more detail below:

- ***Firm storage services*** Firm storage services revenues decreased in the 2013 period as compared to the 2012 period. Decreased storage rates on contracts executed to replace expiring contracts on existing capacity more than offset incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities. Also, less working gas storage capacity was retained for use by our commercial optimization company in the 2013 period as compared to the 2012 period. Revenues generated through the use of storage capacity by our commercial optimization company are reflected as merchant storage revenues when natural gas we own is withdrawn from storage and sold.

- ***Hub services and merchant storage*** Hub services and merchant storage revenues (which include revenues from sales of natural gas by our commercial optimization company) increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period is due to an increase in volumes sold and an increase in price of natural gas sold by our commercial optimization company. The volume and timing of natural gas sales by our commercial optimization company are largely driven by market opportunities.

- ***Other*** Other revenues increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period was due to an increase in crude oil sales associated with liquids removal activities at our Bluewater facility.

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- ***Storage-related costs Hub services and merchant storage*** Hub services and merchant storage-related costs (which includes costs associated with natural gas sold by our commercial optimization company) increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period is due to the increase in volumes of natural gas sold by our commercial optimization company.

- ***Storage-related costs Firm storage services*** Firm storage services related costs decreased in the 2013 period as compared to the 2012 period. The decrease in the 2013 period as compared to the 2012 period is primarily due to a reduction in storage and transportation capacity leased from third parties. Additionally, lower volumes of fuel were utilized for injection activities in the 2013 period as compared to the 2012 period.

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

- ***Field operating costs*** Field operating costs increased in the 2013 period as compared to the 2012 period. The primary reason for such an increase in the 2013 period as compared to the 2012 period is attributable to an increase in insurance costs and growth in personnel costs, including equity-indexed compensation costs. Also, the 2013 period reflects an increase in costs associated with our liquids removal activities at our Bluewater facility as compared to the 2012 period.

- ***General and administrative expenses*** General and administrative expenses increased in the 2013 period as compared to the 2012 period. The 2013 period reflects an increase in costs associated with the continued expansion of our business and growth in personnel costs, including equity-indexed compensation costs. Additionally, we recognized approximately $0.3 million and $0.3 million of equity-indexed compensation expense associated with equity-indexed compensation awards granted by PAA during the 2013 and 2012 periods, respectively. 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 2013 period as compared to the 2012 period. The increase resulted primarily from an increased amount of depreciable assets resulting from capacity expansions at our Pine Prairie and Southern Pines facilities.

- ***Interest expense, net of capitalized interest*** Interest expense, net of capitalized interest, increased in the 2013 period when compared to the 2012 period. Interest expense, on a gross basis, decreased to approximately $3.6 million in the 2013 period as compared to approximately $3.8 million in the 2012 period due to lower average interest rates in the 2013 period as compared to the 2012 period and was partially offset by higher average debt balances in the 2013 period as compared to the 2012 period. Capitalized interest decreased from approximately $2.1 million in the 2012 period to approximately $0.9 million in the 2013 period. The decrease was primarily the result of an increase in assets in-service and lower average interest rates.

Six Months Ended June 30, 2013 as Compared to the Six Months Ended June 30, 2012

Revenues, Volumes and Related Costs. As noted in the table above, our total revenues net of storage-related costs increased during the six months ended June 30, 2013 (the 2013 period) when compared to the six months ended June 30, 2012 (the 2012 period). The primary reasons for such increase are incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities, the results of PNG Marketing, LLC (our commercial optimization company) and an increase in crude oil sales associated with liquids removal activities at our Bluewater facility. These and other significant variances related to these periods are discussed in more detail below:

• ***Firm storage services*** Firm storage services revenues increased in the 2013 period as compared to the 2012 period. Incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities were partially offset by decreased storage rates on contracts executed to replace expiring contracts on existing capacity. Also, additional working gas storage capacity was retained for use by our commercial optimization company in the 2013 period as compared to the 2012 period. Revenues generated through the use of storage capacity by our commercial optimization company are reflected as merchant storage revenues when natural gas we own is withdrawn from storage and sold.

• ***Hub services and merchant storage*** Hub services and merchant storage revenues (which include revenues from sales of natural gas by our commercial optimization company) increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period is due to an increase in volumes sold and an increase in price of natural gas sold by our commercial optimization company. The volume and timing of natural gas sales by our commercial optimization company are largely driven by market opportunities.

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• ***Other*** Other revenues increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period was due to an increase in crude oil sales associated with liquids removal activities at our Bluewater facility.

• ***Storage-related costs Hub services and merchant storage*** Hub services and merchant storage-related costs (which includes costs associated with natural gas sold by our commercial optimization company) increased in the 2013 period as compared to the 2012 period. The primary reason for the increase in the 2013 period as compared to the 2012 period is due to the increase in volumes of natural gas sold by our commercial optimization company.

• ***Storage-related costs Firm storage services*** Firm storage services related costs decreased in the 2013 period as compared to the 2012 period. The decrease in the 2013 period as compared to the 2012 period is primarily due to a reduction in storage and transportation capacity leased from third parties. Additionally, lower volumes of fuel were utilized for injection activities in the 2013 period as compared to the 2012 period.

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

• ***Field operating costs*** Field operating costs increased in the 2013 period as compared to the 2012 period. The primary reason for such an increase in the 2013 period as compared to the 2012 period is attributable to an increase in insurance costs and growth in personnel costs, including equity-indexed compensation costs. Also, the 2013 period reflects an increase in costs associated with our liquids removal activities at our Bluewater facility as compared to the 2012 period.

• ***General and administrative expenses*** General and administrative expenses increased in the 2013 period as compared to the 2012 period. The 2013 period reflects an increase in costs associated with the continued expansion of our business and growth in personnel costs, including equity-indexed compensation costs. Additionally, we recognized approximately $0.6 million and $0.8 million of equity-indexed compensation expense associated with equity-indexed compensation awards granted by PAA during the 2013 and 2012 periods, respectively. 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 2013 period as compared to the 2012 period. The increase resulted primarily from an increased amount of depreciable assets resulting from capacity expansions at our Pine Prairie and Southern Pines facilities.

• ***Interest expense, net of capitalized interest*** Interest expense, net of capitalized interest, increased in the 2013 period when compared to the 2012 period. Interest expense, on a gross basis, decreased to approximately $7.3 million in the 2013 period as compared to approximately $7.9 million in the 2012 period due to lower average interest rates in the 2013 period as compared to the 2012 period and was partially offset by higher average debt balances in the 2013 period as compared to the 2012 period. Capitalized interest decreased from approximately $4.5 million in the 2012 period to approximately $2.2 million in the 2013 period. The decrease was primarily the result of an increase in assets in-service and lower average interest rates.

Outlook

Overall market conditions during the quarter ended June 30, 2013 for both hub services and firm storage services were more challenging than those during the quarter ended June 30, 2012. During the quarter ended June 30, 2013, rolling seasonal spreads (October to January), which are a proxy for the current intrinsic value of storage, ranged from $0.27 to $0.35 per million British thermal unit (MMBtu), representing ten year lows for this time of the year and were less than half of the levels experienced in the year earlier quarter, which ranged from $0.60 to $0.81 per MMBtu. Volatility levels, which impact the value we are able to realize on a short-term basis from our hub service and merchant storage activities, also decreased during the quarter ended June 30, 2013 relative to the quarter ended June 30, 2012.

Longer term, we believe several factors will contribute to meaningful growth in North American natural gas demand that will bolster the market need for and the commercial value of natural gas storage. These fundamental factors include (i) exports of North American volumes of LNG, (ii) construction of new gas-fired power plants, (iii) sustained fuel switching from coal to natural gas among existing power plants and (iv) growth in base-level industrial demand. As a result, we remain optimistic about the intermediate- to long-term intrinsic value of our natural gas storage assets and storage services.

However, based on current market conditions and the natural gas futures curve, the seasonal spreads for the next few years reflect a directionally similar picture to the challenging market conditions we are currently experiencing in 2013. The continuation of such current conditions may adversely impact our hub services activities as well as the lease rates our customers are willing to pay for firm storage services with respect to new capacity under construction and existing capacity upon expirations of existing term leases,

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many of which are at rates above current market levels. If current conditions persist into 2014 and beyond, it will likely have a negative impact on our cash flows during such periods relative to our current cash flow levels. A meaningful reduction in our cash flow level could, among other things, reduce our borrowing capacity under our credit facility, impact our ability to remain in compliance with our debt covenants, impair our ability to maintain our current distribution level or require us to raise additional equity capital. In addition, we can provide no assurances that our organic growth and acquisition efforts will be successful.

Liquidity and Capital Resources

Overview

Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to storage costs incurred, natural gas purchases and other operating and general and administrative expenses, interest payments on our outstanding debt and distributions to our owners, (ii) maintenance and expansion capital expenditures, including purchases of base gas, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our short-term and 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 agreement, and/or proceeds from the issuance of additional equity or debt securities.

Credit Agreement

Our senior unsecured credit agreement, which was most recently amended in June 2012, provides for (i) $350 million under a revolving credit facility, which may be increased at our option to $550 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the GO Bond 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, unless extended. The purchasers of the two GO Bond Term Loans have the right to put, at par, to PNG the GO Bond Term Loans in August 2016, unless extended. The GO Bonds mature by their terms in May 2032 and August 2035, respectively.

Our credit agreement contains covenants and events of default. Our 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 June 30, 2013, borrowings of approximately $345.7 million were outstanding under our credit agreement, which includes approximately $145.7 million under the revolving credit facility. Additionally, we had approximately $10,000 of outstanding letters of credit under our revolving credit facility. As of June 30, 2013, we were in compliance with the covenants, including the financial ratios, contained in our credit agreement. Based on the most restrictive covenant, at June 30, 2013 our incremental borrowing ability under our credit agreement was limited to approximately $147 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 and proceeds from recent equity issuances are adequate to fund our current capital program.

PAA Financial Support

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA s ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guarantees or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us. As of June 30, 2013, outstanding parental guarantees issued by PAA

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to third parties on behalf of PNG Marketing were approximately $15 million. No amounts were due to PAA as of June 30, 2013 under such guarantees and no payments were made to PAA under such guarantees during the three months ended June 30, 2013.

Sources of Liquidity

Our current sources of liquidity include:

- cash generated from operations;
- borrowings under our credit agreement;
- issuances of additional partnership units; and
- debt offerings.

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

We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (Traditional Shelf). All issuances of equity securities associated with our continuous offering program, as discussed further below, have been issued pursuant to the Traditional Shelf. At June 30, 2013, we had approximately $969 million of unsold securities available under the Traditional Shelf.

During the first quarter of 2013, we entered into an equity distribution agreement with a financial institution pursuant to which we may offer and sell, through this financial institution as our sales agent, common units representing limited partner interests having an aggregate offering price of up to $75 million. Sales of such common units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by our sales agent and us. Under the terms of the agreement, we have the option to sell common units to our sales agent as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, we will enter into a separate terms agreement with the sales agent. Through June 30, 2013, we issued an aggregate of 1.4 million common units under this agreement, generating net proceeds of approximately $30.8 million, including our general partner s proportionate capital contribution.

To maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for future expansion projects (beyond the projects currently under development) with a combination of additional equity and retained cash flow in excess of distributions.

For a discussion of the impact that the price of natural gas might have on our operations and liquidity and capital resources, see Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Working Capital

Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven primarily by changes in accounts receivable and accounts payable, natural gas inventory balances and short-term debt. These changes are primarily affected by factors such as credit extended to, and the timing of collections from, our customers, timing differences between the acquisition and sale of natural gas inventory (including cash settlement and margin requirements on related derivative instruments) and our level of spending for maintenance and expansion activity. As of June 30, 2013 we had a working capital surplus of approximately $2.7 million.

Historical Cash Flow Information

The following table presents a summary of our cash flows for the six months ended June 30, 2013 and 2012 (in thousands):

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	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
Net cash provided by (used in):				
Operating activities	$	81,345	$	42,246
Investing activities		(22,454)		(26,739)
Financing activities		(58,572)		(15,509)
Net increase/(decrease) in cash	$	319	$	(2)
Adjusted EBITDA	$	62,139	$	57,484

Operating Activities. The primary drivers of cash flow from our operations are (i) the collection of amounts related to the storage and sale of natural gas, and (ii) the payment of amounts related to purchases of natural gas and expenses, principally storage and transportation related costs, field operating costs and general and administrative expenses. Cash provided by operating activities is significantly impacted in periods where we are increasing or decreasing the amount of inventory in storage. In the month that we pay for stored natural gas, we borrow under our credit facility to pay for the natural gas, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored natural gas. Cash from operating activities is also impacted in a similar manner by the timing of cash settlement of derivatives associated with physical purchases and sales of natural gas. Settlements of such derivatives (which qualify for hedge accounting) are reflected as a component of accumulated other comprehensive income/(loss) until the applicable natural gas inventory is sold. Volumes and timing of our merchant storage activities are largely driven by market opportunities. The primary reason for the increase in cash flows provided by operations in the 2013 period as compared to the 2012 is related to our merchant storage activities. During the 2013 period, sales volumes and prices increased as compared to 2012 period. Additionally, the timing of sales and corresponding cash settlements and a reduction in natural gas inventory held for merchant storage activities as of June 30, 2013 as compared to June 30, 2012 beneficially impacted cash flows provided by operating activities

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

Financing Activities. Our financing activities primarily consist of (i) the payment of distributions to our unitholders and general partner, (ii) funding of capital expansion efforts (including organic growth projects and acquisitions), (iii) proceeds from the issuance of additional partnership units and (iv) borrowings and repayments under our credit agreement associated with inventory purchases and sales (including related derivatives) in conjunction with our merchant storage activities. The primary reasons for the increase in cash used by financing activities in the 2013 period as compared to the 2012 period are associated with our merchant storage activities and partially offset by the issuance of additional equity during the 2013 period. Lower inventory levels held for merchant storage activities at the end of the 2013 period resulted in a reduction in outstanding short-term borrowings to fund hedge inventory as cash generated from such inventory sales was utilized to repay the associated short-term borrowings. During the 2012 period inventory levels were increasing which required the utilization of additional short-term borrowings to fund such purchases. Additionally, proceeds generated from equity issuances during the 2013 period to fund future capital expansion activities were utilized to repay long-term debt until such anticipated capital expansion expenditures are incurred resulting in a net reduction in long-term borrowings over the course of the 2013 period. During the 2012 period, additional long-term borrowings were made primarily to fund capital expansion activities for the period.

Capital Expenditures and Distributions to our Unitholders and General Partner

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

Capital Expenditures. We currently forecast capital expansion expenditures for 2013 of approximately $42 million to $46 million (including capitalized interest), primarily related to the ongoing expansion of our Pine Prairie and Southern Pines facilities and the related base gas required to operate the facilities. Expansion capital expenditures for the six months ended June 30, 2013 were approximately $23.4 million. We expect to fund our capital expenditures with cash generated from operations, borrowings under our credit agreement and/or equity issuances under our equity distribution agreement. Additionally, we are forecasting approximately $0.6 million of maintenance capital expenditures in 2013, of which approximately $0.2 million was incurred through June 30, 2013.

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Distributions to Unitholders and General Partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On August 14, 2013, 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 11 to the condensed consolidated financial statements.

Commitments

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

The following table includes our best estimate of the amounts and timing of the payments due under our contractual obligations as of June 30, 2013 (in millions):

	Total	2013	2014	2015	2016	2017	Thereafter
Long-term debt, interest and fees (1)	$ 531.3	$ 7.0	$ 14.1	$ 209.4	$ 300.8	$	$
Storage/transportation agreements and leases	30.1	7.2	7.9	5.2	3.2	2.9	3.7
Purchase obligations (2)	17.1	3.6	1.8	1.9	1.9	1.8	6.1
Other long-term liabilities	1.6	0.2	0.8	0.3	0.2	0.1	
Subtotal	580.1	18.0	24.6	216.8	306.1	4.8	9.8
Natural gas purchases (3)	50.7	19.4	22.6	4.9	3.8		
Total	$ 630.8	$ 37.4	$ 47.2	$ 221.7	$ 309.9	$ 4.8	$ 9.8

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

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

(3) Amounts are based on estimated volumes and market prices of committed obligations as of June 30, 2013. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit and Parental Guarantees. Our $550 million senior unsecured credit agreement provides us with the ability to issue letters of credit. In connection with our use of certain leased storage and transportation assets and the purchase of natural gas by our commercial optimization company, we have periodically provided certain suppliers and counterparties with irrevocable standby letters of credit to secure our obligations for such purchases. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our consolidated balance sheet in the month the services are provided or when we take delivery of the natural gas purchased. In certain instances, parental guarantees have been provided by PAA in lieu of letters of credit. As of June 30, 2013, we had approximately $10,000 of outstanding letters of credit under our credit agreement. Additionally, approximately $15 million of parental guarantees issued by PAA on behalf of PNG Marketing were outstanding as of June 30, 2013.

Off-Balance Sheet Arrangements

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

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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 2012 Annual Report on Form 10-K.

Forward-Looking Statements

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

- 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, the number of customers competing to acquire such services and the availability of alternatives to the services we offer;

- 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;

- a continuation of reduced volatility and/or lower spreads in natural gas markets for an extended period of time;

- factors affecting our ability to realize revenues from hub services and merchant storage transactions involving uncontracted or unutilized capacity at our facilities;

- operational, geologic or other factors that affect the timing or amount of crude oil and other liquid hydrocarbons that we are able to produce in conjunction with the operation of our Bluewater facility;

- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- 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;

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

- the impact of operational, geologic and commercial factors that could result in an inability on our part to satisfy our contractual commitments and obligations, including the impact of equipment performance, cavern operating pressures, cavern temperature variances, salt creep and subsurface conditions or events;

- risks related to the ownership, development and operation of natural gas storage facilities, including the risk of explosions at our 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;

- the effects of competition;

- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

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- 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;
- the operations or financial performance of assets or businesses that we acquire;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- increased costs or unavailability of insurance;

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

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

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risk Factors discussed in Item 1A of our 2012 Annual Report on Form 10-K. 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

We are exposed to various market risks, including commodity price risk and interest rate risk. We use various derivative instruments to manage such risks. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring exchange cleared positions, as well as physical volumes, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We utilize natural gas derivatives to hedge commodity price risk inherent in our operations. Our objectives for these derivatives include hedging anticipated purchases and sales and stored inventory, and managing our anticipated base gas requirements and storage capacity utilization associated with natural gas or the related storage of natural gas. We manage these exposures with various instruments, including exchange-cleared futures and options. See Note 10 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

Interest Rate Risk

We utilize interest rate derivatives to hedge interest rate risk associated with our variable rate debt. Our objective for these derivatives is to hedge the cash flow variability associated with our interest payments as a result of market fluctuations in interest

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rates. We manage these exposures with over-the-counter, LIBOR-based interest rate swaps. See Note 10 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

The fair value of our derivatives as of June 30, 2013 and the change in fair value that would be expected from a 10% price/rate increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Increase(1)	Effect of 10% Decrease(1)
Natural gas derivatives	$ 1.4	$ (4.3)	$ 4.3
Interest rate derivatives	$ (0.6)	$ 0.1	$ (0.1)

(1) Positive numbers reflect an increase in fair value and negative numbers reflect a decrease in fair value.

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Commodity and interest rate sensitivities were calculated by assuming an across-the-board 10% increase or decrease. In the event of an actual 10% change in near-term commodity prices or interest rates, the fair value of our derivative portfolio would typically change less than that shown in a table, as commodity prices and interest rates do not typically change in a linear fashion.

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

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. See Note 11 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 2012 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. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

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

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SIGNATURES

Pursuant to the requirements of 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: August 7, 2013	By:	/s/ GREG L. ARMSTRONG		
		Name:	Greg L. Armstrong	
		Title:	Chairman and Chief Executive Officer (Principal Executive Officer)	
Date: August 7, 2013	By:	/s/ DEAN LIOLLIO		
		Name:	Dean Liollio	
		Title:	President	
Date: August 7, 2013	By:	/s/ AL SWANSON		
		Name:	Al Swanson	
		Title:	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	

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EXHIBIT INDEX

3.1	Certificate of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.2	Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. dated August 16, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 20, 2010).
3.3	Amendment No. 1 dated February 2, 2012 to Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 8, 2012).
3.4	Certificate of Formation of PNGS GP LLC (incorporated by reference to Exhibit 3.3 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.5	Amended and Restated Limited Liability Company Agreement of PNGS GP LLC dated May 5, 2010 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
10.1	Form of PNG LTIP Grant Letter for Officers (February 2013) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed on May 8, 2013).
10.2	Form of Special PAA LTIP Grant Letter (February 2013) (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed on May 8, 2013).
31.1*	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2*	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1*	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2*	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.