BUCKEYE PARTNERS, L.P.
Form 10-Q
November 08, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2011

OR

¨ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from to

Commission file number 1-9356

Buckeye Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**23-2432497**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification number)**
One Greenway Plaza Suite 600 Houston, TX	**77046**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (832) 615-8600

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject

to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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 x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

Limited partner units and Class B units outstanding as of November 2, 2011: 85,941,866 and 7,175,839, respectively.

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PART I. FINANCIAL INFORMATION

Item 1. *Financial Statements*

BUCKEYE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per unit amounts)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue:				
Product sales	$ 884,436	$ 564,044	$ 2,775,698	$ 1,633,958
Transportation and other services	232,475	170,813	670,841	499,349
Total revenue	1,116,911	734,857	3,446,539	2,133,307
Costs and expenses:				
Cost of product sales and natural gas storage services	881,596	560,248	2,773,899	1,628,630
Operating expenses	96,776	68,685	266,909	204,037
Depreciation and amortization	31,230	15,062	87,227	44,259
General and administrative	15,054	11,349	47,751	35,438
Goodwill impairment expense	169,560		169,560	
Total costs and expenses	1,194,216	655,344	3,345,346	1,912,364
Operating income (loss)	(77,305)	79,513	101,193	220,943
Other income (expense):				
Earnings from equity investments	2,379	3,391	7,760	8,807
Gain on sale of equity investment			34,112	
Interest and debt expense	(33,199)	(22,082)	(90,292)	(65,088)
Other income (expense)	(75)	140	432	380
Total other income (expense)	(30,895)	(18,551)	(47,988)	(55,901)
Net income (loss)	(108,200)	60,962	53,205	165,042
Less: net income attributable to noncontrolling interests	(1,500)	(49,021)	(4,391)	(130,324)
Net income (loss) attributable to Buckeye Partners, L.P.	$ (109,700)	$ 11,941	$ 48,814	$ 34,718
Earnings (loss) per unit:				
Basic	$ (1.18)	$ 0.60	$ 0.55	$ 1.74

Diluted	$ (1.18)	$ 0.60	$ 0.54	$ 1.74
Weighted average number of units outstanding:				
Basic	92,982	19,952	89,499	19,952
Diluted	92,982	19,952	89,831	19,952

See Notes to Unaudited Condensed Consolidated Financial Statements.

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BUCKEYE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In thousands)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income (loss)	$ (108,200)	$ 60,962	$ 53,205	$ 165,042
Other comprehensive income (loss):				
Change in value of derivatives	(83,565)		(92,659)	
Amortization of interest rate swaps	242		724	
Gain on settlement of treasury lock, net of amortization	(12)		464	
Amortization of benefit plan costs	(154)		(394)	
Total other comprehensive loss	(83,489)		(91,865)	
Comprehensive income (loss)	$ (191,689)	$ 60,962	$ (38,660)	$ 165,042

See Notes to Unaudited Condensed Consolidated Financial Statements.

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BUCKEYE PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except unit amounts)

(Unaudited)

	September 30, 2011	December 31, 2010
Assets:		
Current assets:		
Cash and cash equivalents	$ 16,196	$ 13,626
Trade receivables, net	175,995	167,274
Construction and pipeline relocation receivables	6,156	6,803
Inventories	384,306	351,605
Derivative assets	27,330	1,634
Prepaid and other current assets	80,868	85,689
Total current assets	690,851	626,631
Property, plant and equipment, net	3,738,178	2,305,884
Equity investments	67,400	107,047
Goodwill	761,283	432,124
Intangible assets, net	249,382	44,067
Other non-current assets	50,836	58,463
Total assets	$ 5,557,930	$ 3,574,216
Liabilities and partners capital:		
Current liabilities:		
Line of credit	$ 346,800	$ 284,300
Current portion of long-term debt		1,525
Accounts payable	68,882	68,530
Derivative liabilities	1,656	17,285
Accrued and other current liabilities	183,049	144,880
Total current liabilities	600,387	516,520
Long-term debt	2,315,106	1,519,393
Long-term derivative liabilities	89,515	
Other non-current liabilities	189,209	128,043
Total liabilities	3,194,217	2,163,956
Commitments and contingent liabilities		
Partners capital:		
Buckeye Partners, L.P. capital:		
Limited Partners (85,923,830 and 71,436,099 units outstanding as of September 30, 2011 and December 31, 2010, respectively)	2,067,607	1,413,664
Class B Units (7,175,839 and 0 units outstanding as of September 30, 2011 and December 31, 2010, respectively)	391,238	

Accumulated other comprehensive loss	(113,124)	(21,259)
Total Buckeye Partners, L.P. capital	2,345,721	1,392,405
Noncontrolling interests	17,992	17,855
Total partners capital	2,363,713	1,410,260
Total liabilities and partners capital	$ 5,557,930	$ 3,574,216

See Notes to Unaudited Condensed Consolidated Financial Statements.

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BUCKEYE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	Nine Months Ended September 30,	
	2011	**2010**
Cash flows from operating activities:		
Net income	$ 53,205	$ 165,042
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of equity investment	(34,112)	
Value of ESOP shares released	1,183	3,480
Depreciation and amortization	87,227	44,259
Goodwill impairment expense	169,560	
Net changes in fair value of derivatives	(150,433)	(16,152)
Non-cash deferred lease expense	3,091	3,176
Amortization of unfavorable storage contracts	(4,813)	
Earnings from equity investments	(7,760)	(8,807)
Distributions from equity investments	1,922	11,027
Amortization of other non-cash items	10,074	7,552
Change in assets and liabilities, net of amounts related to acquisitions:		
Trade receivables	922	(9,530)
Construction and pipeline relocation receivables	647	5,251
Inventories	(9,590)	56,657
Prepaid and other current assets	8,121	31,289
Accounts payable	(3,691)	(377)
Accrued and other current liabilities	(36,724)	(2,367)
Other non-current assets	11,669	3,059
Other non-current liabilities	81,564	2,548
Total adjustments from operating activities	128,857	131,065
Net cash provided by operating activities	182,062	296,107
Cash flows from investing activities:		
Capital expenditures	(191,368)	(49,275)
Acquisition of interest in equity investment	(5,723)	(13,512)
Deposit in anticipation of acquisition	(500)	
Acquisitions, net of cash acquired	(1,079,411)	(1,269)
Proceeds from sale of equity investment	85,000	
Net proceeds from disposal of property, plant and equipment	573	22,448
Net cash used in investing activities	(1,191,429)	(41,608)
Cash flows from financing activities:		
Net proceeds from issuance of units	736,977	
Proceeds from exercise of unit options	2,226	4,275
Issuance of long-term debt	647,530	
Repayment of long term-debt	(1,525)	(4,644)
Borrowings under BPL Credit Facilities	1,100,232	175,900

Repayments under BPL Credit Facilities	(952,532)	(233,900)
Net borrowings (repayments) under BES Credit Facilities	62,500	(28,000)
Debt issuance costs	(9,968)	(3,245)
Repayment of debt assumed in BORCO acquisition	(318,167)	
Costs associated with agreement and plan of merger	(1,415)	(4,514)
Distributions paid to noncontrolling partners of Buckeye Partners, L.P.	(4,260)	(145,516)
Proceeds from settlement of treasury lock	497	
Distributions paid to partners of Buckeye GP Holdings L.P.		(36,507)
Distributions paid to unitholders	(250,158)	
Net cash provided by (used in) financing activities	1,011,937	(276,151)
Net increase (decrease) in cash and cash equivalents	2,570	(21,652)
Cash and cash equivalents Beginning of period	13,626	37,574
Cash and cash equivalents End of period	$ 16,196	$ 15,922

See Notes to Unaudited Condensed Consolidated Financial Statements.

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BUCKEYE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

(In thousands)

(Unaudited)

	Buckeye Partners, L.P. Unitholders							
	General Partner	Limited Partners	Class B Units	Management Units	Equity Gains on Issuance of Buckeye Limited Partner Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Partners capital - January 1, 2011	$	$ 1,413,664	$	$	$	$ (21,259)	$ 17,855	$ 1,410,260
Net income		45,311	3,503				4,391	53,205
Acquisition of 80% interest in BORCO							276,508	276,508
Acquisition of remaining interest in BORCO							(278,211)	(278,211)
Costs associated with agreement and plan of merger		(1,415)						(1,415)
Distributions paid to partners		(250,158)						(250,158)
Issuance of units to First Reserve for BORCO acquisition		152,772	254,619					407,391
Issuance of units to Vopak for BORCO acquisition		36,041	60,069					96,110
Issuance of units to institutional investors		350,001	75,000					425,001
Equity issuance costs		(2,700)	(1,953)					(4,653)
Net proceeds from issuance of LP Units in underwritten public offering		316,629						316,629
Amortization of unit-based compensation awards		6,588						6,588
Exercise of LP Unit options		2,226						2,226
Services Company s non-cash ESOP distributions							(1,410)	(1,410)
Distributions paid to noncontrolling interests							(4,260)	(4,260)
Amortization of benefit plan costs						(394)		(394)
Change in value of derivatives						(92,659)		(92,658)
Amortization of interest rate swaps						724		723
Amortization of treasury lock settlement						(33)		(33)
Proceeds from settlement of treasury lock						497		497
Noncash accrual for distribution equivalent rights		(892)						(892)
Other		(460)					3,119	2,659
Partners capital - September 30, 2011	$	$ 2,067,607	$ 391,238	$	$	$ (113,124)	$ 17,992	$ 2,363,713
Partners capital - January 1, 2010	$ 7	$ 236,545	$	$ 3,225	$	$ 2,557	$ 1,209,960	$ 1,452,294

Net income	34,068	650			130,324		165,042
Costs associated with agreement and plan of merger	(2,746)	(52)			(4,129)		(6,927)
Distributions paid to partners of BGH	(35,823)	(684)					(36,507)
Recognition of unit-based compensation charges	941	18					959
Amortization of unit-based compensation awards					5,159		5,159
Exercise of LP Unit options					4,275		4,275
Services Company s non-cash ESOP distributions					(2,639)		(2,639)
Distributions paid to noncontrolling interests					(145,516)		(145,516)
Change in value of derivatives					(58,772)		(58,772)
BGH s investment in LP units					4,503		4,503
Other					690		690
Partners capital - September 30, 2010	$ 7	$ 232,985	$	$ 3,157	$	$ 2,557	$ 1,143,855	$ 1,382,561

See Notes to Unaudited Condensed Consolidated Financial Statements.

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BUCKEYE PARTNERS, L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Partnership Organization

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership (MLP), and its limited partnership units representing limited partner interests (LP Units) are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Buckeye GP LLC (Buckeye GP is our general partner. Buckeye GP is a wholly owned subsidiary of Buckeye GP Holdings L.P. (BGH), a Delaware limited partnership that was previously publicly traded on the NYSE prior to BGH s merger with a wholly owned subsidiary of Buckeye (see below for further information). As used in these Notes to Unaudited Condensed Consolidated Financial Statements, *we*, *us*, *our* and *Buckeye* mean Buckeye Partners, L.P. and, where the context requires, includes our subsidiaries.

We were formed in 1986 and own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 6,100 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of over 64 million barrels. In 2011, we acquired (i) the Bahamas Oil Refining Company International Limited (BORCO) terminal facility in Freeport, Grand Bahama, The Bahamas, with a total installed capacity of approximately 21.6 million barrels, (ii) 33 refined petroleum products terminals with a total storage capacity of over 10 million barrels and approximately 650 miles of refined petroleum products pipelines (see Note 2) and (iii) a 124-mile pipeline and terminal in Bangor, Maine with approximately 140,000 barrels of storage capacity and a terminal in Portland, Maine through a 50/50 joint venture with approximately 725,000 barrels (see Note 2). In addition, we operate and maintain approximately 3,400 miles of other pipelines under agreements with major oil and gas, petrochemical and chemical companies, and perform certain engineering and construction management services for third parties. We also own and operate a high performance natural gas storage facility in northern California, and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals.

We operate and report in five business segments: Pipelines & Terminals; International Operations; Natural Gas Storage; Energy Services; and Development & Logistics. Effective January 1, 2011, we realigned our five business segments. We combined the Pipeline Operations and Terminalling & Storage segments into one segment, the Pipelines & Terminals segment, and moved our terminal in Yabucoa, Puerto Rico, previously included as part of the Terminalling & Storage segment, to a new International Operations segment with the BORCO facility. See Note 20 for a discussion of our business segments.

On November 19, 2010, we consummated a transaction pursuant to a plan and agreement of merger (the Merger Agreement) with our general partner, BGH, BGH s general partner and our subsidiary, Grand Ohio, LLC (Merger Sub). Pursuant to the Merger Agreement, Merger Sub was merged into BGH, with BGH as the surviving entity (the Merger). In the transaction, the incentive compensation agreement (also referred to as the incentive distribution rights) held by our general partner was cancelled, the general partner units held by our general partner (representing an approximate 0.5% general partner interest in us) were converted to a non-economic general partner interest, all of the economic interest in BGH was acquired by us and BGH unitholders received aggregate consideration of approximately 20.0 million of our LP Units.

Buckeye Pipe Line Services Company (Services Company) was formed in 1996 in connection with the establishment of the Buckeye Pipe Line Services Company Employee Stock Ownership Plan (the ESOP). At September 30, 2011, Services Company owned approximately 1.6% of our LP Units. Services Company employees provide services to our operating subsidiaries. Pursuant to a services agreement entered into in December 2004, our operating subsidiaries reimburse Services Company for the costs of the services provided by Services Company. Services Company has been consolidated into our financial statements.

Basis of Presentation and Principles of Consolidation

These consolidated financial statements reflect the financial results of BGH for periods prior to the effective date of the Merger. BGH is considered the surviving consolidated entity for accounting purposes, although Buckeye

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BUCKEYE PARTNERS, L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

is the surviving consolidated entity for legal and reporting purposes. The Merger was accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger did not result in gain or loss recognition. Costs incurred associated with the Merger were charged directly to partners capital. Under applicable accounting guidance, the exchange of BGH s units for our LP Units was accounted for as a BGH equity issuance and BGH was the surviving entity for accounting purposes. Consequently, the name on these financial statements for periods prior to the Merger has been changed from Buckeye GP Holdings L.P. to Buckeye Partners, L.P.

The reconciliation of Buckeye s net income, as historically reported, to the net income reported in these financial statements for the three and nine months ended September 30, 2010 is as follows (in thousands):

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
Buckeye s net income, as previously reported	$ 63,113	$ 170,816
Adjustments:		
Depreciation and amortization (1)	1,115	3,348
Costs and expenses (2)	(3,198)	(8,860)
Other (3)	(68)	(262)
Net income	$ 60,962	$ 165,042

(1) Represents the amortization of the market value of LP Units issued in August 1997 in connection with the restructuring of Services Company s ESOP. The market value of those LP Units was $64.2 million, and this amount was recorded as a deferred charge and is being amortized on a straight-line basis over 13.5 years. This deferred charge was not previously included in Buckeye s net income because Services Company was consolidated with BGH, but not Buckeye, for periods prior to the effective date of the Merger.

(2) Amounts include payroll and benefits costs, professional fees, certain state franchise taxes, insurance costs and miscellaneous other expenses incurred by BGH.

(3) Includes interest expense on Services Company s debt and commitment fees on BGH s credit facility. The interest expense was not previously included in Buckeye s net income because Services Company was consolidated with BGH, but not Buckeye, for periods prior to the effective date of the Merger.

Pursuant to the Merger Agreement, BGH s unitholders received a total of approximately 20.0 million of Buckeye s LP Units in the aggregate in exchange for all outstanding BGH common units and management units. As a result, the number of Buckeye s LP Units outstanding increased from 51.6 million to 71.4 million on the date of the Merger. However, for historical reporting purposes, the impact of this change was accounted for as a reverse split of BGH s units of 0.705 to 1.0, together with the addition of Buckeye s existing LP Units. Therefore, since BGH was the surviving accounting entity, the weighted average number of LP Units outstanding used for basic and diluted earnings (loss) per unit calculations are BGH s historical weighted average common units outstanding adjusted for the reverse unit split and the addition of Buckeye s existing units. Amounts reflecting historical BGH unit and per unit amounts included in this report have been restated for the reverse unit split.

The condensed consolidated financial statements and the accompanying notes are prepared in accordance with U.S. generally accepted accounting principles (GAAP) and the rules of the U.S. Securities and Exchange Commission (SEC). The financial statements include our accounts on a consolidated basis. We have eliminated all intercompany transactions in consolidation. The consolidated financial statements include the financial results of our wholly-owned subsidiaries and the financial results of Services Company on a consolidated basis.

Recent Accounting Developments

Fair Value Measurements. In January 2010, the Financial Accounting Standards Board (FASB) issued guidance that requires new disclosures related to fair value measurements. The new guidance requires expanded disclosures related to a gross presentation for Level 3 activity. The new accounting guidance was effective for fiscal years beginning after December 15, 2010 and for interim periods within those years. The new

guidance became

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BUCKEYE PARTNERS, L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

effective for us on January 1, 2011. We have included the enhanced disclosure requirements regarding fair value measurements in Note 14.

In May 2011, the FASB issued guidance that is intended to result in convergence between GAAP and International Financial Reporting Standards requirements for measurement of and disclosures about fair value. The amendments are not expected to have a significant impact on companies applying GAAP. Key provisions of the new guidance include: a prohibition on grouping financial instruments for purposes of determining fair value, except when an entity manages market and credit risks on the basis of the entity s net exposure to the group; an extension of the prohibition against the use of a blockage factor to all fair value measurements (that prohibition currently applies only to financial instruments with quoted prices in active markets); and a requirement that for recurring Level 3 fair value measurements, entities disclose quantitative information about unobservable inputs, a description of the valuation process used and qualitative details about the sensitivity of the measurements. In addition, for items not carried at fair value but for which fair value is disclosed, entities will be required to disclose the level within the fair value hierarchy that applies to the fair value measurement disclosed. This new guidance is effective for interim and annual periods beginning after December 15, 2011. We do not expect the adoption of this guidance to have an impact on our consolidated financial statements.

Intangibles, Goodwill and Other. In December 2010, the FASB issued guidance that amended the goodwill impairment test for reporting units with zero or negative carrying amounts. The objective of this new guidance was to address questions about entities with reporting units with zero or negative carrying amounts because some entities concluded that the first step of the goodwill impairment test is passed in those circumstances because the fair value of their reporting unit will generally be greater than zero. The new guidance was effective for fiscal years and interim periods, within those years, beginning after December 15, 2010. Our adoption did not have any material impact on our consolidated financial statements.

In September 2011, the FASB issued guidance that will amend testing goodwill for impairment. Under the revised guidance, entities testing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step 1 of the goodwill impairment test). If entities determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step impairment test would be required. The amended guidance does not change how goodwill is calculated or assigned to reporting units nor revise the requirement to test goodwill for impairment annually or between annual tests if events or circumstances warrant. However, it does revise the examples of events and circumstances that an entity should consider. The amendments are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Early adoption is permitted. We do not expect the adoption of this guidance to have an impact on our consolidated financial statements. For the goodwill interim impairment testing for the Natural Gas Storage reporting unit (see Note 8), we did not apply the amended guidance as described above.

Business Combinations. In December 2010, the FASB issued guidance that clarifies disclosures related to pro forma information for business combinations that occurred in the current period. The amendments specify that if an entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The amendments also expand the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The new guidance was effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. We have included the enhanced disclosure requirements regarding pro forma information for business combinations in Note 2.

Presentation of Comprehensive Income. In June 2011, the FASB issued guidance that will require companies to present the components of net income and other comprehensive income either as one continuous statement or as two consecutive statements. The guidance eliminates the option to present components of other comprehensive income as part of the statement of changes in unitholders equity. The guidance does not change the items which must be reported in other comprehensive income, how such items are measured or when they must be reclassified to net income. The new guidance is effective for interim and annual periods beginning after December 15, 2011. Because

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

this guidance impacts presentation only, it will have no effect on our financial condition, results of operations or cash flows.

2. ACQUISITIONS AND DISPOSITIONS

Acquisitions

The acquisitions of terminals from an affiliate of Royal Dutch Shell plc (Shell) and from affiliates of FRC Founders Corporation (First Reserve) and Vopak Bahamas B.V. (Vopak), the acquisition of pipeline and terminal assets from BP Products North America Inc. and its affiliates (BP) and the acquisition of a pipeline, terminal and equity investment from an affiliate of ExxonMobil Corporation (ExxonMobil) located in Maine have been accounted for as business combinations. The total purchase price for these acquisitions was allocated to the fair value of the assets acquired and the liabilities assumed based on an assessment of their fair values at the acquisition date, with amounts exceeding the fair values being recorded as goodwill. The results of their operations have been included in our condensed consolidated financial statements since their respective acquisition dates.

Puerto Rico Terminal Acquisition

On December 10, 2010, we, through a wholly owned subsidiary, acquired a refined petroleum products terminal in Yabucoa, Puerto Rico from an affiliate of Shell for $32.8 million, net of cash acquired of $3.5 million. The terminal includes 44 storage tanks with approximately 4.6 million barrels of gasoline, jet fuel, diesel, fuel oil and crude oil storage capacity. Shell entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. We believe the acquisition of these assets furthers our geographic diversification efforts as this was our first acquisition outside the continental United States and enabled us to participate in a growth market outside our existing system footprint. The operations of these acquired assets are reported in the International Operations segment. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed as follows (in thousands):

Current assets	$ 183
Inventory	867
Property, plant and equipment	31,770
Intangible assets	3,363
Other assets	17,720
Current liabilities	(3,413)
Other non-current liabilities	(17,720)
Allocated purchase price	$ 32,770

During 2011, we completed the acquisition of the refined petroleum products terminal in Yabucoa, Puerto Rico through the acquisition of a Puerto Rican entity, which is undergoing an audit of its Puerto Rico income tax returns for the tax years 2002 through 2005. The Puerto Rico Treasury Department has completed the audit of such years and has informed us that no adjustment is required to the taxable income or losses reported on such years. However, the Puerto Rico Treasury Department has notified the entity of a certain area for discussion on taxable year 2008 related to the possible recapture of investment tax credits previously granted to Shell but has not issued a preliminary or final notice of debt regarding such issue. Pursuant to the purchase and sale agreement we entered into in connection with this acquisition, an affiliate of Shell has assumed the full responsibility, through an indemnity and hold harmless provision, for the payment of any income tax debt that may be assessed by the Puerto Rico Treasury Department under this audit. In the purchase price allocation above, we recorded a $17.7 million liability related to the uncertain outcome of the income tax audit with an offsetting indemnification asset from Shell for the same amount.

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BORCO Acquisition

On December 18, 2010, we, through a wholly owned subsidiary, entered into a sale and purchase agreement with affiliates of First Reserve, pursuant to which we agreed to acquire First Reserve s indirect 80% interest in FR Borco Coop Holdings, L.P. (FRBCH), the indirect owner of BORCO, for $1.15 billion, financed through a combination of debt and equity, including the issuance of Class B units representing limited partner interests (Class B Units) and LP Units to First Reserve. BORCO is the fourth largest oil and petroleum products storage terminal in the world and the largest petroleum products facility in the Caribbean with current storage capacity of approximately 21.6 million barrels. On January 18, 2011, we completed the purchase of First Reserve s interest in BORCO through the acquisition by us of all of the partnership interests in FR Borco Topco, L.P., which indirectly owned First Reserve s interest.

Vopak, which is based in The Netherlands, owned the remaining 20% interest in FRBCH. On February 16, 2011, Vopak sold its 20% interest in FRBCH to us for approximately $276.5 million of cash and equity, which is a proportionate price and on the same terms and conditions as those in the sale and purchase agreement with First Reserve.

The following table presents the aggregate consideration paid or issued to complete the BORCO acquisition (in thousands):

	First Reserve	Vopak	Combined
Cash consideration	$ 644,049	$ 164,616	$ 808,665
Fair value of LP Units and Class B Units issued (1)	407,391	96,110	503,501
Cash paid on behalf of the sellers (2)	96,241	15,780	112,021
Consideration issued to effect the transactions	$ 1,147,681	$ 276,506	$ 1,424,187

(1) On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve, which represented a negotiated value of $400.0 million of consideration. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak, which represented a negotiated value of $100.0 million of consideration. In accordance with accounting for business combinations, the fair values of the units issued to First Reserve and Vopak on their respective acquisition dates were determined to be $407.4 million and $96.1 million, respectively.

(2) Approximately $79.3 million was to be held in escrow related to Bahamian transfer taxes payable, approximately $23.2 million was used to make certain payments to BORCO s operator and indirect minority owner and to pay certain fees and expenses incurred by FRBCH and its affiliates in connection with the transaction and approximately $9.5 million was used to pay bonuses to employees that became payable as a result of the transaction.

On January 13, 2011, we issued $650.0 million aggregate principal amount of 4.875% Notes due 2021 (the 4.875% Notes) in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price of the BORCO acquisition.

On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the BORCO acquisition. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of the BORCO acquisition. Equity issuance costs incurred on these transactions were approximately $4.6 million. The remaining purchase price was funded with cash on hand at closing and borrowings under our Prior BPL Credit Facility (as defined in Note 11).

On January 18, 2011, in connection with the BORCO acquisition, we repaid all of BORCO s outstanding indebtedness and settled BORCO s interest rate derivative instruments, collectively representing approximately $318.2 million.

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The results of operations of the BORCO acquisition are included in our condensed consolidated financial statements from the date of acquisition and are included in our International Operations segment. The acquisition cost has been allocated to assets acquired and liabilities assumed based on estimated fair values at the acquisition date, with amounts exceeding the fair value recorded as goodwill, which represents both expected synergies from combining the BORCO acquisition with our existing operations and the economic value attributable to future expansion projects resulting from this acquisition. Fair values have been developed using recognized business valuation techniques and are subject to change pending final valuation analysis. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed, on a preliminary basis, as follows (in thousands):

Current assets	$ 40,842
Inventory	1,645
Property, plant and equipment	1,105,278
Intangible assets	206,000
Other assets	415
Goodwill	498,719
Current liabilities	(54,627)
Debt, including interest rate derivative instruments	(318,167)
Other non-current liabilities	(55,918)
Allocated purchase price	$ 1,424,187

Pipelines and Terminals Acquisition

On June 1, 2011, we acquired 33 refined petroleum products terminals with total storage capacity of over 10 million barrels and approximately 650 miles of refined petroleum products pipelines from BP for $166.0 million. The terminal and pipeline assets are located in the Midwestern, Southeastern and Western United States. BP entered into multiple commercial contracts with us concurrent with the acquisition relating to the continued usage of these assets. We believe the acquisition of these assets further extends our operations into new, key geographic markets. The operations of these acquired assets are reported in the Pipelines & Terminals segment. We funded this acquisition with borrowings under our Prior BPL Credit Facility. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed, on a preliminary basis, as follows (in thousands):

Inventory	$ 1,161
Property, plant and equipment	174,597
Intangible assets	8,940
Environmental and other liabilities	(18,722)
Allocated purchase price	$ 165,976

Acquisition of Refined Petroleum Products Terminals and Pipeline in Maine

On July 19, 2011, we acquired a 124-pipeline and terminal in Bangor, Maine (Bangor terminal) with approximately 140,000 barrels of storage capacity and a terminal in Portland, Maine (South Portland terminal) through a 50/50 joint venture with Irving Oil Terminals Inc. with approximately 725,000 barrels of storage capacity from an affiliate of ExxonMobil for $23.5 million in cash. The South Portland terminal is operated by our Development & Logistics segment. We accounted for the South Portland terminal using the equity method of accounting. See Note 7 for equity investment information. The pipeline, Bangor terminal and equity investment are reported in the Pipelines & Terminals segment. We financed this acquisition with borrowings under our Prior BPL Credit Facility. The purchase price was allocated principally to

property, plant, and equipment, on a preliminary basis.

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Unaudited Pro forma Financial Results

Our condensed consolidated statements of operations do not include earnings from BORCO prior to January 18, 2011, the effective date of the BORCO acquisition. The following table presents selected unaudited pro forma earnings information for the three and nine months ended September 30, 2011 and 2010, as if the BORCO acquisition had occurred on January 1, 2010. This pro forma information does not give effect to any of the other acquisitions we have made since January 1, 2010, as pro forma results including those acquisitions would not be materially different from the information presented in our accompanying condensed consolidated statements of operations. The pro forma information presented below was prepared using BORCO s historical financial data and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information was prepared for comparative purposes only and is not necessarily indicative of what our consolidated financial results would have been had we actually acquired BORCO on January 1, 2010 or the results that may be attained in the future (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue:				
As reported	$ 1,116,911	$ 734,857	$ 3,446,539	$ 2,133,307
Pro forma adjustments		49,370	8,422	146,489
Pro forma revenue	$ 1,116,911	$ 784,227	$ 3,454,961	$ 2,279,796
Net income (loss) attributable to Buckeye Partners, L.P.:				
As reported	$ (109,700)	$ 11,941	$ 48,814	$ 34,718
Pro forma adjustments		15,687	4,772	50,173
Pro forma net income (loss) attributable to Buckeye Partners, L.P.:	$ (109,700)	$ 27,628	$ 53,586	$ 84,891
Pro forma earnings (loss) per unit:				
Basic	$ (1.18)	$ 0.77	$ 0.59	$ 2.37
Diluted	$ (1.18)	$ 0.77	$ 0.59	$ 2.37
Pro forma weighted average number of units outstanding:				
Basic	92,982	35,720	90,670	35,826
Diluted	92,982	35,720	91,002	35,826

Dispositions

On May 11, 2011, we sold our 20% interest in West Texas LPG Pipeline Limited Partnership (WT LPG) to affiliates of Atlas Pipeline Partners L.P. for $85.0 million. WT LPG owns a 2,295-mile common-carrier pipeline system that transports natural gas liquids from points in New

Mexico and Texas to Mont Belvieu, Texas for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WT LPG. The proceeds from the sale were used to fund a portion of our internal growth capital projects in 2011. We recognized a gain of $34.1 million on the sale of our interest in WT LPG.

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3. COMMITMENTS AND CONTINGENCIES

Claims and Proceedings

In the ordinary course of business, we are involved in various claims and legal proceedings, some of which are covered by insurance. We are generally unable to predict the timing or outcome of these claims and proceedings. Based upon our evaluation of existing claims and proceedings and the probability of losses relating to such contingencies, we have accrued certain amounts relating to such claims and proceedings, none of which are considered material.

In June 2009, the Pipeline Hazardous Materials Safety Administration (PHMSA) proposed penalties totaling approximately $0.6 million as a result of alleged violations of various pipeline safety requirements raised as a result of PHMSA s 2008 integrated inspection of our procedures and records for operations and maintenance, operator qualification, and integrity management as well as field inspections of locations in Pennsylvania, Ohio, Illinois, Michigan and Colorado. We are contesting portions of the proposed penalty. The timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

In April 2010, PHMSA proposed penalties totaling approximately $0.5 million in connection with a tank overfill incident that occurred at our facility in East Chicago, Indiana in May 2005 and other related personnel qualification issues raised as a result of PHMSA s 2008 Integrity Inspection. We are contesting the proposed penalty. The timing or outcome of this appeal cannot reasonably be determined at this time.

In January 2011, PHMSA issued a proposed penalty totalling $0.1 million in connection with certain procedural and personnel qualification issues related to product release that occurred in Boothwyn, Pennsylvania in April 2008. We are contesting portions of the proposed penalty. The timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

Environmental Contingencies

We are subject to federal, state and local laws and regulations relating to the protection of the environment. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at our operating sites. We record environmental liabilities at a specific site when environmental assessments occur or remediation efforts are probable and can be reasonably estimated based upon past experience, discussions with operating personnel, advice of outside engineering or consulting firms, discussions with general counsel or current facts and circumstances. We monitor the environmental liabilities regularly and record adjustments to our initial estimates, from time to time, to reflect changing circumstances and estimates based upon additional developments or information obtained in subsequent periods. Recoveries of environmental remediation expenses from other parties are recorded when their receipt is deemed probable.

In accordance with our accounting policy, we recorded operating expenses, net of recoveries, of $4.6 million and $2.2 million during the three months ended September 30, 2011 and 2010, respectively, related to environmental expenditures unrelated to claims and proceedings. For the nine months ended September 30, 2011 and 2010, we recorded operating expenses, net of recoveries, of $9.4 million and $7.6 million, respectively, related to environmental expenditures unrelated to claims and proceedings. At September 30, 2011 and December 31, 2010, approximately $ 17.8 million and $ 10.5 million, respectively, were recorded in accrued and other current liabilities (see Note 10) and $ 38.8 million and $ 20.3 million, respectively, were recorded in other non-current liabilities (see Note 12), respectively.

Ammonia Contract Contingencies

On November 30, 2005, Buckeye Development & Logistics I LLC (BDL) (formerly Buckeye Gulf Coast Pipe Lines, L.P.) purchased an ammonia pipeline and other assets from El Paso Merchant Energy-Petroleum Company (EPME), a subsidiary of El Paso Corporation (El Paso). As part of the transaction, BDL assumed the obligations of EPME under several contracts involving monthly purchases and sales of ammonia. EPME and BDL agreed, however, that EPME would retain the economic risks and benefits associated with those contracts until their

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expiration at the end of 2012. To effectuate this agreement, BDL passes through to EPME both the cost of purchasing ammonia under a supply contract and the proceeds from selling ammonia under three sales contracts. For the vast majority of monthly periods since the closing of the pipeline acquisition, the pricing terms of the ammonia contracts have resulted in ammonia supply costs exceeding ammonia sales proceeds. The amount of the shortfall generally increases as the market price of ammonia increases.

EPME has informed BDL that, notwithstanding the parties agreement, it will not continue to pay BDL for shortfalls created by the pass-through of ammonia costs in excess of ammonia revenues. EPME encouraged BDL to seek payment by invoking a $40.0 million guaranty made by El Paso, which guaranteed EPME s obligations to BDL. If EPME fails to reimburse BDL for these shortfalls, then such unreimbursed shortfalls could exceed the $40.0 million cap on El Paso s guaranty. To the extent the unreimbursed shortfalls significantly exceed the $40.0 million cap, the resulting costs incurred by BDL could adversely affect our financial position, results of operations and cash flows. To date, BDL has continued to receive payment for ammonia costs under the contracts at issue. BDL has not called on El Paso s guaranty and believes only BDL may invoke the guaranty. EPME, however, contends that El Paso s guaranty is the source of payment for the shortfalls, but has not clarified the extent to which it believes the guaranty has been exhausted. We, in cooperation with EPME, have terminated one of the ammonia sales contracts. Given the uncertainty of future ammonia prices and EPME s future actions, we continue to believe we may have risk of loss in connection with the two remaining ammonia sales contracts and an ammonia supply contract and, at this time, are unable to estimate the amount of any such losses we might incur in the future. We are assessing our options in the event that we are unable to mitigate our risk with respect to the remaining contracts through termination of such contracts by other means, including commencing litigation or pursuing other recourse against EPME and El Paso, with respect to this matter.

Leases Where We are Lessee

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Lease expense is charged to operating expenses on a straight-line basis over the period of expected benefit. Contingent rental payments are expensed as incurred. Total rental expense for the three months ended September 30, 2011 and 2010 was $7.4 million and $5.7 million, respectively. For the nine months ended September 30, 2011 and 2010, total rental expense was $22.0 million and $16.2 million, respectively. The following table presents minimum lease payment obligations under our operating leases with the amount for 2011 consisting of the remainder of 2011 (October 1 through December 31) and all other years consisting of the total amount for the full year (in thousands):

	Office space and other (1)	Equipment (2)	Land Leases (3)	Total
2011 (remainder)	$ 509	$ 877	$ 1,167	$ 2,553
2012	2,345	3,487	4,890	10,722
2013	2,555	3,608	5,017	11,180
2014	2,655	2,093	5,100	9,848
2015	2,758		5,224	7,982
Thereafter	17,200		358,590	375,790
Total	$ 28,022	$ 10,065	$ 379,988	$ 418,075

(1) Includes leases of space in office buildings and related land leases with respect to our Albany terminal.
(2) Includes BORCO facility leases for tugboats and a barge in our International Operations segment.
(3) Includes leases for inland dock and seabed in connection with our operations in the International Operations segment and leases for subsurface underground gas storage rights and surface rights in connection with our operations in the Natural Gas Storage segment. We may cancel the Natural Gas Storage segment leases if the storage reservoir is not used for underground storage of natural gas or the removal or injection thereof for a continuous period of two consecutive years. Lease expense associated with the Natural Gas Storage

segment leases, which is being recognized on a straight-line basis over 44 years, was approximately $1.8 million for each of the three months ended September 30, 2011 and 2010 and $5.4 million for each of the nine months ended September 30, 2011 and 2010. At September 30, 2011

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and December 31, 2010, the balance of our Natural Gas Storage segment deferred lease liability was $16.4 million and $13.3 million, respectively. We estimate that this deferred lease liability will continue to increase through 2032, at which time our deferred lease liability is estimated to be approximately $64.7 million. Our deferred lease liability will then be reduced over the remaining 19 years of the lease, since the expected annual lease payments will exceed the amount of lease expense.

Leases Where We are Lessor

We have entered into capacity and other leases with remaining terms from 4 to 12 years that are accounted for as operating leases. All of the agreements provide for negotiated extensions. Future minimum lease payments to be received under such operating leasing arrangements as of December 31, 2011 are as follows, with the amount for 2011 consisting of the remainder of 2011 (October 1 through December 31) and all other years consisting of the total amount for the full year (in thousands):

	Years Ending December 31,
2011 (remainder)	$ 22,943
2012	80,212
2013	43,624
2014	11,526
2015	11,152
Thereafter	50,891
Total	$ 220,348

4. INVENTORIES

Our inventory amounts were as follows at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Refined petroleum products (1)	$ 371,452	$ 340,659
Materials and supplies	12,854	10,946
Total inventories	$ 384,306	$ 351,605

(1) Ending inventory was 133.2 million and 134.9 million gallons of refined petroleum products at September 30, 2011 and December 31, 2010, respectively.

At September 30, 2011 and December 31, 2010, approximately 96% and 94% of our refined petroleum products inventory was hedged, respectively. Hedged inventory is valued at current market prices with the change in value of the inventory reflected in our condensed consolidated statements of operations. Inventory not accounted for as a fair value hedge is accounted for at weighted average cost.

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5. PREPAID AND OTHER CURRENT ASSETS

Prepaid and other current assets consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Prepaid insurance	$ 10,899	$ 8,865
Insurance receivables	8,133	8,886
Ammonia receivable	1,797	1,295
Margin deposits	4,643	18,833
Prepaid services	11,084	24,359
Unbilled revenue	9,982	3,263
Tax receivable	2,834	120
Prepaid taxes	4,103	5,417
Customer deposits	4,505	2,657
Other	22,888	11,994
Total prepaid and other current assets	$ 80,868	$ 85,689

6. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Land	$ 226,211	$ 64,905
Rights-of-way	108,532	97,529
Pad gas	29,346	29,346
Buildings and leasehold improvements	122,729	109,585
Jetties and subsea pipelines	158,281	
Gas storage facility	196,643	196,077
Pipeline and terminals	2,866,776	1,982,049
Vehicles, equipment and office furnishings	90,637	72,901
Construction in progress	329,693	66,642
Total property, plant and equipment	4,128,848	2,619,034
Less: Accumulated depreciation	(390,670)	(313,150)
Total property, plant and equipment, net	$ 3,738,178	$ 2,305,884

Depreciation expense was $27.7 million and $13.7 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, depreciation expense was $77.0 million and $40.4 million, respectively.

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7. EQUITY INVESTMENTS

We own interests in related businesses that are accounted for using the equity method of accounting. The following table presents our equity investments, all included within the Pipelines & Terminals segment, at the dates indicated (in thousands):

	Ownership	September 30, 2011	December 31, 2010
Muskegon Pipeline LLC	40.0%	$ 14,490	$ 14,552
Transport4, LLC	25.0%	446	341
West Shore Pipe Line Company	34.6%	46,498	43,563
West Texas LPG Pipeline Limited Partnership (1)			48,591
South Portland Terminal LLC (2)	50.0%	5,966	
Total equity investments		$ 67,400	$ 107,047

(1) In May 2011, we sold our 20% interest in this investment. See Note 2 for further information.
(2) See Note 2 for a discussion of the acquisition of this interest.

The following table presents earnings from equity investments for the periods indicated (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Muskegon Pipeline LLC	$ 454	$ 488	$ 552	$ 1,059
Transport4, LLC	43	51	143	120
West Shore Pipe Line Company	1,638	1,229	4,524	3,730
West Texas LPG Pipeline Limited Partnership (1)		1,623	2,297	3,898
South Portland Terminal LLC (2)	244		244	
Total earnings from equity investments	$ 2,379	$ 3,391	$ 7,760	$ 8,807

(1) In May 2011, we sold our 20% interest in WT LPG. Amounts for WT LPG are included through the date of the sale of our interest.
(2) See Note 2 for a discussion of the acquisition of this interest.

Combined income statement data for the periods indicated for our equity investments are summarized below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010

Revenues	$ 19,485	$ 36,546	$ 80,989	$ 103,845
Costs and expenses	(8,140)	(19,690)	(43,106)	(55,934)
Non-operating expense	(2,812)	(3,983)	(9,632)	(11,021)
Net income (1)	$ 8,533	$ 12,873	$ 28,251	$ 36,890

(1) In May 2011, we sold our 20% interest in WT LPG. Amounts for WT LPG are included through the date of the sale of our interest.

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8. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. We do not amortize goodwill; rather, we test our goodwill (at the reporting unit level) for impairment on January 1 of each fiscal year, and more frequently if circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. The following table summarizes our goodwill amounts by segment at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Pipelines & Terminals:		
Purchase of general partner interests in 2004	$ 210,066	$ 210,066
Acquisition of six terminals in June 2000	11,355	11,355
Acquisition of Albany Terminal in 2008	26,829	26,829
Subtotal	248,250	248,250
International Operations:		
Acquisition of BORCO in 2011	498,719	
Natural Gas Storage:		
Acquisition of Lodi Gas in 2008	169,560	169,560
Impairment charge in 2011	(169,560)	
Subtotal		169,560
Energy Services:		
Acquisition of Farm & Home in 2008	1,132	1,132
Development & Logistics:		
Purchase of general partner interests in 2004	13,182	13,182
Total goodwill	$ 761,283	$ 432,124

During the three months ended September 30, 2011, we concluded the continued downward performance in operating income and Adjusted EBITDA (as defined in Note 20) in the Natural Gas Storage segment due to decreases in contracted storage prices relating to low volatility in natural gas prices and compressed seasonal spreads was an impairment indicator; therefore, we performed an interim goodwill impairment test.

The first step of the goodwill impairment test determines whether an impairment exists by comparing the fair value of a reporting unit with its carrying amount, including goodwill. If the estimated fair value of the reporting unit exceeds its carrying amount, no impairment is necessary. If the carrying amount of a reporting unit exceeds its estimated fair value, the second step measures the amount of impairment by comparing the implied fair value of the reporting unit goodwill with its carrying amount of that goodwill. An entity would assign the fair value of a reporting unit to all of the assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of a reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The estimate of the fair value of the Natural Gas reporting unit was determined using a combination of an expected present value of future cash flows and a market multiple

valuation method. The present value of future cash flows is estimated using (i) discrete financial forecasts, which rely on management s estimates of revenue, operating expenses and volumes, (ii) long-term growth rates and (iii) appropriate discount rates. The market multiple valuation method uses appropriate market multiples from comparable companies on the reporting unit s earnings before interest, tax, depreciation and amortization. Due to the current market conditions, we weighted 100% to the expected present value of future cash flows method.

Our Natural Gas reporting unit failed step one of the goodwill impairment test; therefore, we performed the second step. As a result of our step two analysis, we concluded goodwill in the Natural Gas segment was fully

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impaired and recorded a non-cash goodwill impairment charge of $169.6 million as of September 30, 2011. We considered the goodwill impairment an indicator of impairment related to the long-lived assets associated with the Natural Gas reporting unit. Accordingly, we evaluated these assets for impairment in connection with our step two analysis and concluded that no impairment of the long-lived asset existed.

Intangible Assets

Intangible assets include customer relationships and contracts. These intangible assets have definite lives and are being amortized on a straight-line basis over their estimated useful lives ranging from 5 to 25 years. Our amortizable customer contracts are contracts that were acquired in connection with the acquisition of BDL in March 1999, the acquisition of the Taylor, Michigan terminal in December 2005, the acquisition of certain pipeline and terminal assets in November 2009, the acquisition of the Yabucoa, Puerto Rico terminal in 2010 and the acquisition of pipelines and terminals from BP in June 2011 (see Note 2 for further discussion). The customer contracts are being amortized over their contractual life of approximately 5 years.

The customer relationships resulted from the acquisition of Farm & Home Oil Company LLC (Farm & Home) in 2008 and BORCO in 2011. We determined, through an analysis of historical customer attrition rates at Farm & Home, that an appropriate recovery period for customer relationships is approximately 12 years. For BORCO, due to the high customer demand at the facility, the level of customer service being provided, the expansion capabilities of the facility, the potential of customer recontracting rates and the location of the facility in relation to international shipping routes, we anticipate the customer relationships will extend well beyond the existing contract terms with a recovery period of approximately 25 years. Intangible assets consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Customer relationships	$ 247,663	$ 41,663
Accumulated amortization	(17,112)	(8,600)
Net carrying amount	230,551	33,063
Customer contracts	25,320	16,380
Accumulated amortization	(6,489)	(5,376)
Net carrying amount	18,831	11,004
Total intangible assets, net	$ 249,382	$ 44,067

For the three months ended September 30, 2011 and 2010, amortization expense related to intangible assets was $3.3 million and $1.1 million, respectively. For the nine months ended September 30, 2011 and 2010, amortization expense related to intangible assets was $9.6 million and $3.3 million, respectively. Amortization expense related to intangible assets is expected to be approximately $3.3 million for the remainder of 2011 (October 1 through December 31), $13.4 million for 2012, $13.4 million for 2013, $13.2 million for 2014 and $12.2 million for 2015.

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9. OTHER NON-CURRENT ASSETS

Other non-current assets consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Prepaid services	$ 1,468	$ 5,836
Unbilled revenue		2,163
Derivative assets	37	3,892
Debt issuance costs	15,072	11,184
Insurance receivables	7,518	8,826
Indemnification asset (see Note 2)	17,720	17,720
Other	9,021	8,842
Total other non-current assets	$ 50,836	$ 58,463

10. ACCRUED AND OTHER CURRENT LIABILITIES

Accrued and other current liabilities consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Taxes - other than income	$ 19,141	$ 20,698
Accrued employee benefit liability	3,817	3,817
Environmental liabilities	17,787	10,471
Interest payable	23,675	30,700
Payable for ammonia purchase	2,865	2,354
Unearned revenue	12,101	18,776
Compensation and vacation	14,779	13,134
Accrued capital expenditures	22,116	2,032
Deferred consideration	1,000	2,010
Customer deposits	8,633	5,389
Unfavorable storage contracts (1)	10,994	
Other	46,141	35,499
Total accrued and other current liabilities	$ 183,049	$ 144,880

(1) See Note 12 for a discussion of the unfavorable storage contracts acquired in connection with the BORCO acquisition.

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11. LONG-TERM DEBT

Long-term debt consists of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
4.625% Notes due July 15, 2013 (1)	$ 300,000	$ 300,000
5.300% Notes due October 15, 2014 (1)	275,000	275,000
5.125% Notes due July 1, 2017 (1)	125,000	125,000
6.050% Notes due January 15, 2018 (1)	300,000	300,000
5.500% Notes due August 15, 2019 (1)	275,000	275,000
4.875% Notes due February 1, 2021 (1)	650,000	
6.750% Notes due August 15, 2033 (1)	150,000	150,000
BPL Credit Facilities (2)	592,500	98,000
BES Credit Facility		284,300
Services Company 3.60% ESOP Notes due March 28, 2011		1,531
Retirement premium		(6)
Total debt	2,667,500	1,808,825
Other, including unamortized discounts and fair value hedges	(5,594)	(3,607)
Subtotal debt	2,661,906	1,805,218
Less: Current portion of long-term debt and line of credit	(346,800)	(285,825)
Total long-term debt	$ 2,315,106	$ 1,519,393

(1) We make semi-annual interest payments on these notes based on the rates noted above with the principal balances outstanding to be paid on or before the due dates as shown above.

(2) Includes the Credit Facility and Prior BPL Credit Facility as defined below.

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The fair values of our aggregate debt and credit facilities were estimated to be $2,789.0 million and $1,897.5 million at September 30, 2011 and December 31, 2010, respectively. The fair values of the fixed-rate debt were estimated by observing market trading prices and by comparing the historic market prices of our publicly-issued debt with the market prices of other MLPs publicly-issued debt with similar credit ratings and terms. The fair values of the variable-rate debt are their carrying amounts, as the carrying amount reasonably approximates fair value due to the variability of the interest rates.

Notes Offering

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price for our acquisition of BORCO (see Note 2). In connection with this offering, we settled a treasury lock agreement, which resulted in the receipt of a settlement of $0.5 million, which is being amortized as a reduction to interest expense over the ten-year term of the 4.875% Notes (see Note 14).

Bridge Loans

In December 2010, in connection with the proposed BORCO acquisition, we obtained a commitment from commercial banks for senior unsecured bridge loans in an aggregate amount up to $595 million (or up to $775 million in the event we purchased both First Reserve s 80% interest and Vopak s 20% interest in FRBCH) (the Bridge Loans). The commitment was to expire upon the earliest to occur of the termination date as defined in the BORCO sale and purchase agreement, the consummation of the BORCO acquisition, the termination of the BORCO sale and purchase agreement or 120 days after December 18, 2010. We paid $2.0 million of fees in December 2010 associated with these Bridge Loans. In January 2011, we terminated the Bridge Loans upon issuance of the 4.875% Notes.

Services Company ESOP Notes

At December 31, 2010, Services Company had total debt outstanding of $1.5 million consisting of 3.60% Senior Secured Notes due March 28, 2011 payable by the ESOP to a third-party lender, which were repaid on March 28, 2011.

Credit Facility

On September 26, 2011, Buckeye and its indirect wholly-owned subsidiary, Buckeye Energy Services LLC (BES), as borrowers, entered into a Revolving Credit Agreement (the Credit Facility) with SunTrust Bank, as administrative agent and other lenders to provide for a $1.25 billion senior unsecured revolving credit agreement of which we have a borrowing capacity of $1.25 billion and BES has a sublimit of $500.0 million. The Credit Facility s maturity date is September 26, 2016, with an option to extend the term for two successive one-year periods and a $500.0 million accordion option to increase the commitments. Concurrently with the execution of the Credit Facility, Buckeye and BES borrowed $243.7 million and $318.8 million, respectively, and used the proceeds to repay all amounts outstanding under Buckeye s senior unsecured revolving credit agreement dated November 13, 2006 (Prior BPL Credit Facility) and BES s amended and restated senior revolving credit agreement dates as of June 25, 2010 (BES Credit Facility), respectively, and customary fees and expenses related to the Credit Facility. Buckeye and BES incurred debt issuance costs of approximately $3.6 million and $1.4 million, respectively, related to the Credit Facility. These costs were included in other non-current assets and are being amortized over the Credit Facility terms of five years. As a result of the termination of the Prior BPL Credit Facility and BES Credit Facility, we expensed $0.3 million and $3.0 million, respectively, of unamortized deferred financing costs associated with the credit facilities, which is reflected in interest and debt expense in our condensed consolidated statement of operations.

Under the Credit Facility, interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the applicable borrower for each interest period. The issuing fees for all letters of credit are

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also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the credit ratings assigned to our senior unsecured long-term debt securities. The applicable margin for LIBOR rate loans, swing line loans, and letter of credit fees ranges from 1.0% to 1.75% and the applicable margin for base rate loans ranges from 0% to 0.75%. The borrowers will also pay a fee based on our credit ratings on the actual daily unused amount of the aggregate commitments. At September 30, 2011 and December 31, 2010, Buckeye had $592.5 million and $98.0 million, respectively, and BES had $0 million and $284.3 million, respectively, outstanding under their respective credit agreements. The BES outstanding balances were classified as current liabilities in our condensed consolidated balance sheets as related funds were used to finance current working capital needs. The weighted average interest rate for borrowings under the Credit Facility was 2.71% at September 30, 2011.

The Credit Facility includes covenants limiting, as of the last day of each fiscal quarter, the ratio of consolidated funded debt (Funded Debt Ratio) to consolidated EBITDA, as defined in the Credit Facility, measured for the preceding twelve months, to not more than 5.00 to 1.00. This requirement is subject to a provision for increases to 5.50 to 1.00 in connection with certain future acquisitions. The Funded Debt Ratio is calculated by dividing consolidated debt by annualized EBITDA, which is defined in the Credit Facility as earnings before interest, taxes, depreciation, depletion and amortization determined on a consolidated basis in accordance with generally accepted accounting principles. At September 30, 2011, our Funded Debt Ratio was approximately 4.3 to 1.00. At September 30, 2011, we were not aware of any instances of noncompliance with the covenants under our Credit Facility.

At September 30, 2011 and December 31, 2010, we had committed $1.8 million and $1.4 million, respectively, in support of letters of credit. The obligations for letters of credit are not reflected as debt in our condensed consolidated balance sheets.

12. OTHER NON-CURRENT LIABILITIES

Other non-current liabilities consist of the following at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Accrued employee benefit liabilities (see Note 15)	$ 49,930	$ 49,170
Accrued environmental liabilities	38,817	20,346
Deferred consideration	17,514	16,415
Deferred rent	16,484	13,393
Uncertain tax position liability (see Note 2)	17,720	17,720
Unfavorable storage contracts (1)	41,893	
Other	6,851	10,999
Total other non-current liabilities	$ 189,209	$ 128,043

(1) In determining fair value of assets and liabilities acquired in the BORCO acquisition (see Note 2), we allocated negative fair values to certain unfavorable storage contracts at the date of acquisition and recorded them as current and long-term liabilities in the condensed consolidated balance sheet. The unfavorable storage contracts are being recognized to revenue based on the estimated realization of the fair value established on the acquisition date over the contractual life. At September 30, 2011, amount is net of $4.8 million of recognized revenue. Revenue to be recognized related to these unfavorable storage contracts is expected to be approximately $2.7 million for the remainder of 2011 (October 1 through December 31), $11.0 million for 2012 and 2013, $11.1 million for 2014 and 2015 and $6.0 million for 2016. See Note 10 for the current portion of unfavorable storage contracts.

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13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following table presents the components of accumulated other comprehensive income (loss) (AOCI) in our condensed consolidated balance sheets at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Adjustments to funded status of retirement income guarantee plan and retiree medical plan	$ (10,323)	$ (10,323)
Amortization of interest rate swap	(6,065)	(6,789)
Derivative instruments	(89,515)	3,144
Gain on settlement of treasury lock, net of amortization	464	
Accumulated amortization of retirement income guarantee plan and retiree medical plan	(7,685)	(7,291)
Total accumulated other comprehensive loss	$ (113,124)	$ (21,259)

14. DERIVATIVE INSTRUMENTS, HEDGING ACTIVITIES AND FAIR VALUE MEASUREMENTS

We are exposed to certain risks, including changes in interest rates and commodity prices, in the course of our normal business operations. We use derivative instruments to manage risks associated with certain identifiable and anticipated transactions. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. Typical derivative instruments include futures, forward contracts, swaps and other instruments with similar characteristics.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies 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 used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items. A discussion of our derivative activities by risk category follows.

Interest Rate Derivatives

We utilize forward-starting interest rate swaps to manage interest rate risk related to forecasted interest payments on anticipated debt issuances. This strategy is a component in controlling our cost of capital associated with such borrowings. When entering into interest rate swap transactions, we become exposed to both credit risk and market risk. We are subject to credit risk when the value of the swap transaction is positive and the risk exists that the counterparty will fail to perform under the terms of the contract. We are subject to market risk with respect to changes in the underlying benchmark interest rate that impacts the fair value of the swaps. We manage our credit risk by only entering into swap transactions with major financial institutions with investment-grade credit ratings. We manage our market risk by associating each swap transaction with an existing debt obligation or a specified expected debt issuance generally associated with the maturity of an existing debt obligation.

Our practice with respect to derivative transactions related to interest rate risk has been to have each transaction in connection with non-routine borrowings authorized by the board of directors of Buckeye GP. In February 2009, Buckeye GP s board of directors adopted an interest rate hedging policy which permits us to enter into certain short-term interest rate swap agreements to manage our interest rate and cash flow risks associated with a credit facility. In addition, in July 2009 and May 2010, Buckeye GP s board of directors authorized us to enter into certain transactions, such as forward-starting interest rate swaps, to manage our interest rate and cash flow risks related to certain expected debt issuances associated with the maturity of existing debt obligations.

We expect to issue new fixed-rate debt (i) on or before July 15, 2013 to repay the $300.0 million of 4.625% Notes that are due on July 15, 2013 and (ii) on or before October 15, 2014 to repay the $275.0 million of 5.300% Notes that are due on October 15, 2014, although no assurances can be given that the issuance of fixed-rate debt will

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be possible on acceptable terms. We have entered into six forward-starting interest rate swaps with a total aggregate notional amount of $300.0 million related to the anticipated issuance of debt on or before July 15, 2013 and six forward-starting interest rate swaps with a total aggregate notional amount of $275.0 million related to the anticipated issuance of debt on or before October 15, 2014. The purpose of these swaps is to hedge the variability of the forecasted interest payments on these expected debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. We designated the swap agreements as cash flow hedges at inception and expect the changes in values to be highly correlated with the changes in value of the underlying borrowings.

On January 13, 2011, we issued the 4.875% Notes in an underwritten public offering. In December 2010, in connection with the proposed offering, we entered into a treasury lock agreement to fix the 10-year treasury rate at 3.3375% per annum on a notional amount of $650.0 million. In January 2011, we subsequently cash-settled the treasury lock agreement upon the issuance of the 4.875% Notes and received approximately $0.5 million, which is being recognized as a reduction to interest expense over the term of the 4.875% Notes.

During the three months ended September 30, 2011 and 2010, unrealized losses of $83.6 million and $22.0 million, respectively, were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the forward-starting interest rate swaps. During the nine months ended September 30, 2011 and 2010, unrealized losses of $92.4 million and $58.1 million, respectively, were recorded in accumulated other comprehensive income (loss).

Over the next twelve months, we expect to reclassify $0.9 million of net losses, consisting of loss attributable to forward-starting interest rate swaps terminated in 2008 associated with our 6.050% Notes, partially offset by a gain attributable to the settlement of the treasury lock agreement associated with the 4.875% Notes in January 2011, from accumulated other comprehensive loss to earnings as an increase to interest and debt expense.

Commodity Derivatives

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its physical commodity forward fixed-price purchase and sales contracts. The derivative contracts used to hedge refined petroleum product inventories are designated as fair value hedges. Accordingly, our method of measuring ineffectiveness compares the change in the fair value of New York Mercantile Exchange (NYMEX) futures contracts to the change in fair value of our hedged fuel inventory. The time value component is excluded from our hedge assessment and reported directly in earnings. Hedge accounting is discontinued when the hedged fuel inventory is sold or when the related derivative contracts expire. In addition, we periodically enter into offsetting exchange-traded futures contracts to economically close-out an existing futures contract based on a near-term expectation to sell a portion of our fuel inventory. These offsetting derivative contracts are not designated as hedging instruments and any resulting gains or losses are recognized in earnings during the period. The fair values of futures contracts for inventory designated as hedging instruments in the following tables have been presented net of these offsetting futures contracts.

Our Energy Services segment has not used hedge accounting with respect to its fixed-price contracts. Therefore, our fixed-price contracts and the related futures contracts used to offset the changes in fair value of the fixed-price sales contracts are all marked-to-market in our condensed consolidated balance sheets with gains and losses being recognized in earnings during the period.

In order to hedge the cost of natural gas used to operate our turbine engines at our Linden, New Jersey location, our Pipelines & Terminals segment bought natural gas futures contracts in March 2009 with terms that coincide with the terms of a natural gas supply contract that expired in August 2011. The natural gas futures contracts were designated as cash flow hedges at inception and the change in fair value was recorded in other comprehensive income (OCI). As the forecasted event occurred and was recognized in earnings, the change in fair value was reclassed from OCI to earnings. As of September 30, 2011, there were no designated cash flow hedges of our natural gas supply contracts and the amount that had been recorded in OCI was reclassed to earnings.

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The following table summarizes our commodity derivative instruments outstanding at September 30, 2011 (amounts in thousands of gallons, except as noted):

Derivative Purpose	Volume (1) Current	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives NOT designated as hedging instruments:			
Physical derivative contracts for refined products	9,262	126	Mark-to-market
Futures contracts for refined products	12,726		Mark-to-market
Derivatives designated as hedging instruments:			
Futures contracts for refined products	127,974		Fair Value Hedge

(1) Volume represents absolute value of net notional volume position.
(2) The maximum term for derivatives included in the long-term column is December 2012.

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The following table sets forth the fair value of each classification of derivative instruments at the dates indicated (in thousands):

	September 30, 2011				
	Derivatives NOT Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Carrying Value	Netting Balance Sheet Adjustment	Total
Physical derivative contracts for refined products	$ 7,446	$	$ 7,446	$ (281)	$ 7,165
Futures contracts for refined products	44,226	23,775	68,001	(47,836)	20,165
Total current derivative assets	51,672	23,775	75,447	(48,117)	27,330
Physical derivative contracts	37		37		37
Total non-current derivative assets	37		37		37
Physical derivative contracts for refined products	(1,937)		(1,937)	281	(1,656)
Futures contracts for refined products	(46,406)	(1,430)	(47,836)	47,836	
Total current derivative liabilities	(48,343)	(1,430)	(49,773)	48,117	(1,656)
Interest rate derivatives		(89,515)	(89,515)		(89,515)
Total non-current derivative liabilities		(89,515)	(89,515)		(89,515)
Net derivative assets/(liabilities)	$ 3,366	$ (67,170)	$ (63,804)	$	$ (63,804)

	December 31, 2010				
	Derivatives NOT Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Carrying Value	Netting Balance Sheet Adjustment	Total
Physical derivative contracts for refined products	$ 1,552	$	$ 1,552	$ (30)	$ 1,522
Futures contracts for refined products	36,916		36,916	(36,804)	112
Total current derivative assets	38,468		38,468	(36,834)	1,634
Interest rate derivatives		5,351	5,351	(1,459)	3,892
Total non-current derivative assets		5,351	5,351	(1,459)	3,892
Physical derivative contracts for refined products	(3,930)		(3,930)	30	(3,900)
Futures contracts for refined products	(21,368)	(28,071)	(49,439)	36,804	(12,635)

Futures contracts for natural gas		(206)	(206)		(206)
Interest rate derivatives		(2,003)	(2,003)	1,459	(544)
Total current derivative liabilities	(25,298)	(30,280)	(55,578)	38,293	(17,285)
Net derivative assets/(liabilities)	$ 13,170	$ (24,929)	$ (11,759)	$	$ (11,759)

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Our hedged inventory portfolio extends to the fourth quarter of 2011. The majority of the unrealized net gain of $22.3 million at September 30, 2011 for futures contracts designated as inventory hedging instruments and unrealized gains in the fair values of the underlying hedged refined petroleum product inventories will be realized by the fourth quarter of 2011 as the inventory is sold. At September 30, 2011, open refined petroleum product derivative contracts (represented by the fixed-price contracts and futures contracts for fixed-price sales contracts noted above) varied in duration, but did not extend beyond December 2012. In addition, at September 30, 2011, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

The following table sets forth the location of derivative instruments in our condensed consolidated balance sheets at the dates indicated (in thousands):

	September 30, 2011	December 31, 2010
Derivative assets	$ 27,330	$ 1,634
Other non-current assets	37	3,892
Derivative liabilities	(1,656)	(17,285)
Other non-current liabilities	(89,515)	
Total	$ (63,804)	$ (11,759)

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The gains and losses on our derivative instruments recognized in income were as follows for the periods indicated (in thousands):

		Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
	Location	2011	2010	2011	2010
Derivatives NOT designated as hedging instruments:					
Physical derivative contracts for refined products	Product sales	$ 7,507	$ (1,974)	$ 5,920	$ 6,704
Physical derivative contracts for refined products	Cost of product sales and natural gas storage services	4,277		6,044	
Futures contracts for refined products	Cost of product sales and natural gas storage services	(1,016)	3,428	165	228
Derivatives designated as fair value hedging instruments:					
Futures contracts for refined products	Cost of product sales and natural gas storage services	30,240	(15,159)	(18,591)	(1,946)
Physical Inventory - Hedge items	Cost of product sales and natural gas storage services	(27,768)	20,300	12,515	(3,495)
Ineffectiveness excluding the time value component on fair value hedging instruments:					
Fair value hedge ineffectiveness (excluding time value)	Cost of product sales and natural gas storage services	$ 3,825	$ (1,469)	$ 3,621	$ 9,111
Time value excluded from hedge assessment	Cost of product sales and natural gas storage services	(1,353)	6,609	(9,697)	(14,553)
Net impact on income		$ 2,472	$ 5,140	$ (6,076)	$ (5,442)

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The gains and losses reclassified from AOCI to income and the change in value recognized in OCI on our derivatives were as follows for the periods indicated (in thousands):

		Gain (Loss) Reclassified from AOCI to Income			
		Three Months Ended September 30,		Nine Months Ended September 30,	
	Location	2011	2010	2011	2010
Derivatives designated as cash flow hedging instruments:					
Futures contracts for natural gas	Cost of product sales and natural gas storage services	$ (32)	$ (122)	$ (251)	$ (291)
Futures contracts for refined petroleum products	Cost of product sales and natural gas storage services				
Interest rate contracts	Interest and debt expense	(229)	(241)	(691)	(723)

	Change in Value Recognized in OCI on Derivatives			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Derivatives designated as cash flow hedging instruments:				
Futures contracts for natural gas	$	$ (337)	$ (46)	$ (949)
Interest rate contracts	(83,596)	(21,957)	(92,366)	(58,114)

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the income or market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

Level 1 inputs are based on quoted prices, which are available in active markets for identical assets or liabilities as of the reporting date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 inputs are based on pricing inputs other than quoted prices in active markets and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other

appropriate valuation methodologies and include the following:

Quoted prices in active markets for similar assets or liabilities.

Quoted prices in markets that are not active for identical or similar assets or liabilities.

Inputs other than quoted prices that are observable for the asset or liability.

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Inputs that are derived primarily from or corroborated by observable market data by correlation or other means.

Level 3 inputs are based on unobservable inputs for the asset or liability. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity s own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity s internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument s fair value.

Recurring

The following table sets forth financial assets and liabilities, measured at fair value on a recurring basis, as of the measurement dates, September 30, 2011 and December 31, 2010, and the basis for that measurement, by level within the fair value hierarchy (in thousands):

	September 30, 2011		December 31, 2010	
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)
Financial assets:				
Physical derivative contracts for refined products	$	$ 7,202	$	$ 1,522
Futures contracts for refined products	20,165		112	
Interest rate derivatives				3,892
Financial liabilities:				
Physical derivative contracts for refined products		(1,656)		(3,900)
Futures contracts for refined products			(12,635)	
Futures contracts for natural gas			(206)	
Interest rate derivatives		(89,515)		(544)
Fair value	$ 20,165	$ (83,969)	$ (12,729)	$ 970

The values of the Level 1 derivative assets and liabilities were based on quoted market prices obtained from the NYMEX.

The values of the Level 2 interest rate derivatives were determined using expected cash flow models, which incorporated market inputs including the implied forward LIBOR yield curve for the same period as the future interest swap settlements.

The values of the Level 2 fixed-price contracts assets and liabilities were calculated using market approaches based on observable market data inputs, including published commodity pricing data, which is verified against other

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available market data, and market interest rate and volatility data. Level 2 fixed-price contracts assets are net of credit value adjustments (CVA) determined using an expected cash flow model, which incorporates assumptions about the credit risk of the fixed-price contracts based on the historical and expected payment history of each customer, the amount of product contracted for under the agreement and the customer s historical and expected purchase performance under each contract. The Energy Services segment determined CVA is appropriate because few of the Energy Services segment s customers entering into these fixed-price contracts are large organizations with nationally-recognized credit ratings. The Level 2 fixed-price contracts assets of $7.2 million and $1.5 million as of September 30, 2011 and December 31, 2010, respectively, are net of CVA of ($0.1) million for both periods, respectively. As of September 30, 2011, the Energy Services segment did not hold any net liability derivative position containing credit contingent features.

Non-Recurring

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of possible impairment. During the three and nine months ended September 30, 2011, we recorded a non-cash goodwill impairment charge based on Level 3 inputs. See Note 8 for a discussion of our valuation methodology relating to the goodwill impairment test. For the three and nine months ended September 30, 2011, there were not any fair value adjustments reflected in our condensed consolidated financial statements.

15. PENSIONS AND OTHER POSTRETIREMENT BENEFITS

Services Company, which employs the majority of our workforce, sponsors a retirement income guarantee plan (RIGP), which is a defined benefit plan that generally guarantees employees hired before January 1, 1986 a retirement benefit based on years of service and the employee s highest compensation for any consecutive 5-year period during the last 10 years of service or other compensation measures as defined under the respective plan provisions. The retirement benefit is subject to reduction at varying percentages for certain offsetting amounts, including benefits payable under a retirement and savings plan discussed further below. Services Company funds the plan through contributions to pension trust assets, generally subject to minimum funding requirements as provided by applicable law.

Services Company also sponsors an unfunded post-retirement benefit plan (the Retiree Medical Plan), which provides health care and life insurance benefits to certain of its retirees. To be eligible for these benefits, an employee must have been hired prior to January 1, 1991 and meet certain service requirements.

The components of the net periodic benefit cost for the RIGP and Retiree Medical Plan were as follows for the three months ended September 30, 2011 and 2010 (in thousands):

	RIGP Three Months Ended September 30,		Retiree Medical Plan Three Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$ 86	$ 66	$ 66	$ 74
Interest cost	199	226	508	495
Expected return on plan assets	(59)	(86)		
Amortization of prior service benefit		(11)	(740)	(741)
Amortization of unrecognized losses	260	241	327	223
Settlement charge	406			
Net periodic benefit costs	$ 892	$ 436	$ 161	$ 51

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The components of the net periodic benefit cost for the RIGP and Retiree Medical Plan were as follows for the nine months ended September 30, 2011 and 2010 (in thousands):

	RIGP Nine Months Ended September 30,		Retiree Medical Plan Nine Months Ended September 30,	
	2011	2010	2011	2010
Service cost	$ 222	$ 199	$ 227	$ 221
Interest cost	598	685	1,446	1,486
Expected return on plan assets	(247)	(260)		
Amortization of prior service benefit		(34)	(2,222)	(2,223)
Amortization of unrecognized losses	896	731	933	670
Settlement charge	609			
Net periodic benefit costs	$ 2,078	$ 1,321	$ 384	$ 154

During the nine months ended September 30, 2011, we contributed $2.4 million to the RIGP.

16. UNIT-BASED COMPENSATION PLANS

BGH GP Holdings LLC (BGH GP) has an equity compensation plan (BGH GP Equity Compensation Plan) for certain members of our senior management. Compensation expense recorded with respect to the BGH GP Equity Compensation Plan was $0 and $0.3 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, compensation expense recorded with respect to the BGH GP Equity Compensation Plan was $0 and $0.9 million, respectively.

We award unit-based compensation to employees and directors primarily under the Buckeye Partners, L.P. 2009 Long-Term Incentive Plan (the LTIP). We formerly awarded options to acquire LP Units to employees pursuant to the Buckeye Partners, L.P. Unit Option and Distribution Equivalent Plan (the Option Plan). We recognized compensation expense related to the LTIP and the Option Plan of $1.7 million and $1.3 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, we recognized compensation expense related to the LTIP and the Option Plan of $6.6 million and $3.8 million, respectively. These compensation plans are discussed below.

BGH GP s Override Units

Effective on June 25, 2007, BGH GP instituted the BGH GP Equity Compensation Plan. The BGH GP Equity Compensation Plan included both time-based and performance-based participation in the equity of BGH GP (but not ours) referred to as override units. These override units consisted of three equal tranches of units consisting of Value A, Value B and Operating Units. We are required to record, as compensation expense and a corresponding contribution to unitholders equity, the fair value of the compensation. We are not the sponsor of this plan and have no obligations with respect to it. Compensation expense related to this plan was $0 and $0.3 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2010, compensation expense related to this plan was $0 and $0.9 million, respectively.

On December 31, 2010, the override unit plan was modified. All outstanding Value A and Operating Units were exchanged for LP Units owned by BGH GP. The terms of the Value B Units remained unchanged. The Value B Units will participate in distributions by BGH GP based on the occurrence of an exit event and an investment return of 3.5 times the original investment and an internal rate of return of at least 10% or on a pro-rata basis on an investment return ranging from 2.0 to 3.5 times the original investment and an internal rate of return of at least 10%.

On January 27, 2011, BGH GP established and granted new override units in BGH GP to a member of senior management, which consisted of Value N-1 and Value N-2 Units. The Value N-1 Units will participate in distributions by BGH GP based on the occurrence of an exit event and an investment return of 2.0 times the original investment up to aggregate distributions of $3.0 million. The Value N-2 Units will participate in distributions by

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BGH GP based on the occurrence of an exit event and an investment return of 2.5 times the original investment or on a pro-rata basis on an investment return ranging from 2.0 to 2.5 times the original investment up to aggregate distributions of $5.0 million.

The exit event with respect to the Value B, Value N-1 and Value N-2 Units is generally defined as the sale by ArcLight Capital Partners (ArcLight), Kelso & Company (Kelso) and their affiliates of their interests in BGH GP, the sale of substantially all the assets of BGH GP and its subsidiaries, or any other extraordinary transaction that the Board of Directors of BGH GP determines is an exit event.

The investment return is calculated generally as the sum of all the distributions that ArcLight and Kelso have received from BGH GP prior to and through the exit event, divided by the total amount of capital contributions to BGH GP that ArcLight and Kelso have made prior to the exit event.

The cumulative grant date fair values of the Value B, Value N-1 and Value N-2 Units that remained unvested as of September 30, 2011 are $2.2 million, $0.9 million and $1.1 million, respectively. The vesting of the override units is contingent on a performance condition, namely the completion of the exit event, and a market condition, primarily relating to the receipt of an investment return at a specified multiple and internal rate of return, where applicable. Accordingly, no compensation expense for these override units will be recorded until, and if, an exit event and other requirements occur.

At grant date, the override units were valued using the Monte Carlo simulation method that incorporated the market-based vesting condition into the grant date fair value of the unit awards. The following assumptions were used for grants of the Value N-1 and N-2 Units during the period:

	Three Months Ended March 31, 2011
Equity value in BGH GP (in millions)	$ 410.7
Expected life in years	1
Risk-free interest rate	0.25%
Volatility	25%

LTIP

The LTIP provides for the issuance of up to 1,500,000 LP Units, subject to certain adjustments. After giving effect to the issuance or forfeiture of phantom unit and performance unit awards through September 30, 2011, awards representing a total of 876,914 additional LP Units could be issued under the LTIP.

Under the terms of the Buckeye Partners, L.P. Unit Deferral and Incentive Plan (Deferral Plan), eligible employees were allowed to defer up to 50% of their 2011 and 2010 compensation award under our Annual Incentive Compensation Plan or other discretionary bonus program in exchange for grants of phantom units equal in value to the amount of their cash award deferral (each such unit, a Deferral Unit). Participants also receive one matching phantom unit for each Deferral Unit. Approximately $1.6 million of 2010 compensation awards had been deferred at December 31, 2010, for which 50,660 phantom units (including matching units) were granted during the nine months ended September 30, 2011. These grants are included as granted in the LTIP activity table below.

Awards under the LTIP

During the nine months ended September 30, 2011, the Compensation Committee granted 111,216 phantom units to employees (including the 50,660 phantom units granted pursuant to the Deferral Plan discussed above), 14,000 phantom units to independent directors of Buckeye GP and 122,843 performance units to employees. The amount paid with respect to phantom unit distribution equivalents under the LTIP was $0.8 million and $0.4 million for the nine months ended September 30, 2011 and 2010, respectively.

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The following table sets forth the LTIP activity for the periods indicated (dollars in thousands):

	Number of LP Units	Weighted Average Grant Date Fair Value per LP Unit (1)	Total Value
Unvested at January 1, 2011	364,913	$ 51.11	$ 18,650
Granted	248,059	64.89	16,096
Vested	(15,246)	55.35	(844)
Forfeited	(9,047)	55.91	(506)
Unvested at September 30, 2011	588,679	$ 56.74	$ 33,396

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per LP Unit for forfeited and vested awards is determined before an allowance for forfeitures.

At September 30, 2011, approximately $16.4 million of compensation expense related to the LTIP is expected to be recognized over a weighted average period of approximately 1.5 years.

Unit Option and Distribution Equivalent Plan

The following is a summary of the changes in the LP Unit options outstanding (all of which are vested or are expected to vest) under the Option Plan for the periods indicated (dollars in thousands):

	Number of LP Units	Weighted-Average Strike Price ($/LP Unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at January 1, 2011	241,800	$ 46.98		
Exercised	(79,600)	47.45		
Outstanding at September 30, 2011	162,200	46.75	4.9	$ 2,556
Exercisable at September 30, 2011	157,200	$ 47.25	4.9	$ 2,399

(1) Aggregate intrinsic value reflects fully vested LP Unit options at the date indicated. Intrinsic value is determined by calculating the difference between our closing LP Unit price on the last trading day in September 2011 and the exercise price, multiplied by the number of exercisable, in-the-money options.

The total intrinsic value of options exercised was $1.3 million and $1.5 million during the nine months ended September 30, 2011 and 2010, respectively. At September 30, 2011, total unrecognized compensation cost related to unvested LP Unit options was $0.2 million. We expect to

recognize this remaining cost over a weighted average period of 0.2 years. At September 30, 2011, 333,000 LP Units were available for grant in connection with the Option Plan. However, with the adoption of the LTIP, we do not expect to make any future grants pursuant to the Option Plan. The fair value of options vested was $0.1 million and $0.4 million during the nine months ended September 30, 2011 and 2010, respectively.

17. RELATED PARTY TRANSACTIONS

We are managed by Buckeye GP, our general partner. Services Company is considered a related party with respect to us. As discussed in Note 1, our consolidated financial statements include the financial results of Services Company on a consolidated basis, and all intercompany transactions have been eliminated.

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Services Company, which is beneficially owned by the ESOP, owned 1.3 million of our LP Units (approximately 1.6% of our LP Units outstanding) as of September 30, 2011. Distributions received by Services Company from us on such LP Units are used to fund obligations of the ESOP. Distributions paid to Services Company totalled $2.9 million and $4.5 million for the nine months ended September 30, 2011 and 2010, respectively. Total distributions paid to Services Company decrease over time because Services Company sells LP Units to fund benefits payable to ESOP participants who exit the ESOP.

Prior to the Merger, Buckeye GP received incentive distributions from us pursuant to our partnership agreement and incentive compensation agreement. Incentive distributions were based on the level of quarterly cash distributions paid per LP Unit and the total number of LP Units outstanding. Incentive distribution payments totaled $37.8 million during the nine months ended September 30, 2010.

18. PARTNERS CAPITAL AND DISTRIBUTIONS

Our LP Units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights and privileges available to them under our partnership agreement. Our partnership agreement provides that, without prior approval of our limited partners holding an aggregate of at least two-thirds of the outstanding LP Units, we cannot issue any LP Units of a class or series having preferences or other special or senior rights over the LP Units. In accordance with our partnership agreement, capital accounts are maintained for our general partner and limited partners. In conjunction with the Merger, our partnership agreement was amended.

Class B Units represent a separate class of our limited partnership interests. The Class B Units share equally with the LP Units (i) with respect to the payment of distributions and (ii) in the event of our liquidation. We have the option to pay distributions on the Class B Units with cash or by issuing additional Class B Units, with the number of Class B Units issued based upon the volume-weighted average price of the LP Units for the 10 trading days immediately preceding the date the distributions are declared, less a discount of 15%. The Class B Units have the same voting rights as if they were outstanding LP Units and are entitled to vote as a separate class on any matters that materially adversely affect the rights or preferences of the Class B Units in relation to other classes of partnership interests or as required by law. The Class B Units will convert into LP Units on a one-for-one basis on the earlier of (a) the date on which at least 4 million barrels of incremental storage capacity are placed in service by BORCO or (b) the third anniversary of the closing of the BORCO acquisition.

In April 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

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Summary of Changes in Outstanding Units

The following is a reconciliation of units outstanding for the periods indicated:

	Limited Partners	Class B Units	Total
Units outstanding at December 31, 2010	71,436,099		71,436,099
LP Units issued pursuant to the Option Plan	54,380		54,380
LP Units issued pursuant to the LTIP	14,321		14,321
Issuance of units to First Reserve and Vopak as consideration for BORCO acquisition	3,104,305	5,478,611	8,582,916
Issuance of units to institutional investors (1)	5,794,725	1,314,870	7,109,595
Issuance of units in underwritten public offering	5,520,000		5,520,000
Issuance of Class B Units in lieu of quarterly cash distributions		382,358	382,358
Units outstanding at September 30, 2011	85,923,830	7,175,839	93,099,669

(1) Proceeds were used to fund a portion of the BORCO acquisition.

Distributions

We generally make quarterly cash distributions to unitholders of substantially all of our available cash, generally defined in our partnership agreement as consolidated cash receipts less consolidated cash expenditures and such retentions for working capital, anticipated cash expenditures and contingencies as our general partner deems appropriate. Cash distributions on our LP Units totaled $252.2 million and $185.8 million during the nine months ended September 30, 2011 and 2010, respectively. We also paid distributions in kind to our Class B unitholders by issuing 382,358 Class B Units during the nine months ended September 30, 2011.

On November 4, 2011, we announced a quarterly distribution of $1.0250 per LP Unit that will be paid on November 30, 2011, to LP unitholders of record on November 15, 2011. Total cash distributed to LP unitholders on November 30, 2011 will total approximately $88.4 million. We also expect to issue approximately 138,000 Class B Units in lieu of cash distributions on November 30, 2011, to Class B unitholders of record on November 15, 2011.

19. EARNINGS (LOSS) PER UNIT

Basic and diluted earnings (loss) per unit (includes LP Units and Class B Units) is calculated by dividing net income (loss), after deducting the amount allocated to noncontrolling interests, by the weighted-average number of LP Units and Class B Units outstanding during the period.

Pursuant to the Merger Agreement, BGH s unitholders received a total of approximately 20.0 million of Buckeye s LP Units in the aggregate in exchange for all outstanding BGH common units and management units. As a result, the number of Buckeye s LP Units outstanding increased from 51.6 million to 71.4 million on the date of the Merger. However, for historical reporting purposes, the impact of this change was accounted for as a reverse split of BGH s units of 0.705 to 1.0, together with the addition of Buckeye s existing LP Units. Therefore, since BGH was the surviving accounting entity, the weighted average number of units outstanding used for basic and diluted earnings (loss) per unit calculations are BGH s historical weighted average common units outstanding adjusted for the reverse unit split and the addition of Buckeye s existing LP Units. Amounts reflecting historical BGH unit and per unit amounts included in this report have been restated for the reverse unit split.

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The following table is a reconciliation of the weighted average number of units used in the basic and diluted earnings (loss) per unit calculations for the periods indicated (in thousands, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income (loss) attributable to Buckeye Partners, L.P.	$ (109,700)	$ 11,941	$ 48,814	$ 34,718
Basic:				
Weighted average units outstanding	92,982	19,581	89,499	19,581
Weighted average management units outstanding		371		371
Units for basic	92,982	19,952	89,499	19,952
Earnings (loss) per unit - basic	$ (1.18)	$ 0.60	$ 0.55	$ 1.74
Diluted:				
Units for basic	92,982	19,952	89,499	19,952
Dilutive effect of LP unit options and LTIP awards granted			332	
Units for diluted	92,982	19,952	89,831	19,952
Earnings (loss) per unit - diluted	$ (1.18)	$ 0.60	$ 0.54	$ 1.74

For the three months ended September 30, 2011, there were 367 potential units excluded in computing the dilutive effect of LP unit options and LTIP awards granted in the diluted earnings (loss) per unit as the effect of their inclusion would have been anti-dilutive.

20. BUSINESS SEGMENTS

We operate and report in five business segments: Pipelines & Terminals; International Operations; Natural Gas Storage; Energy Services; and Development & Logistics. Effective January 1, 2011, we realigned our five business segments. We combined the Pipeline Operations and Terminalling & Storage segments into one segment, the Pipelines & Terminals segment, and moved our terminal in Yabucoa, Puerto Rico, previously included as part of the Terminalling & Storage segment, to a new International Operations segment with the BORCO facility. We recast our period-to-period comparisons to conform to the current presentation.

Pipelines & Terminals

The Pipelines & Terminals segment receives refined petroleum products from refineries, connecting pipelines, and bulk and marine terminals and transports those products to other locations for a fee and provides bulk storage and terminal throughput services in the continental United States. This segment owns and operates approximately 6,100 miles of pipeline systems in 17 states. The segment has 95 liquid petroleum products terminals in 21 states with aggregate storage capacity of approximately 37.1 million barrels.

International Operations

The International Operations segment provides marine bulk storage and marine terminal throughput services. The segment has two liquid petroleum product terminals, one in Puerto Rico and one on The Grand Bahama Island in The Bahamas, with an aggregate storage capacity of

26.2 million barrels.

Natural Gas Storage

The Natural Gas Storage segment provides natural gas storage services at a natural gas storage facility in northern California. The facility has approximately 29 Bcf of working natural gas storage capacity and is connected

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to Pacific Gas and Electric s intrastate gas pipelines that service natural gas demand in the San Francisco and Sacramento, California areas.

Energy Services

The Energy Services segment is a wholesale distributor of refined petroleum products in areas also served by our pipelines and terminals assets. This segment recognizes revenues when products are delivered. The segment s products include gasoline, propane and petroleum distillates such as heating oil, diesel fuel and kerosene. The segment also has five terminals with aggregate storage capacity of approximately 1.0 million barrels. The segment s customers consist principally of product wholesalers as well as major commercial users of these refined petroleum products.

Development & Logistics

The Development & Logistics segment provides contract operations, engineering and construction management services as well as asset development services to energy companies throughout the U.S. and internationally. This segment operates approximately 2,700 miles of third-party pipeline and terminals, which are owned principally by major oil and gas, petrochemical and chemical companies, and also acts as a business development arm for many of these same customers. The Development & Logistics segment also includes our ownership and operation of an ammonia pipeline and our majority ownership of the Sabina Pipeline, each located in Texas.

Adjusted EBITDA

Adjusted EBITDA is the primary measure used by senior management, including our Chief Executive Officer, to evaluate our operating results and to allocate our resources. We define EBITDA, a measure not defined under GAAP, as net income (loss) attributable to our unitholders before interest and debt expense, income taxes and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. The EBITDA measure eliminates the significant level of non-cash depreciation and amortization expense that results from the capital-intensive nature of our businesses and from intangible assets recognized in business combinations. In addition, EBITDA is unaffected by our capital structure due to the elimination of interest and debt expense and income taxes. We define Adjusted EBITDA, which is also a non-GAAP measure, as EBITDA plus: (i) non-cash deferred lease expense, which is the difference between the estimated annual land lease expense for our natural gas storage facility in the Natural Gas Storage segment to be recorded under GAAP and the actual cash to be paid for such annual land lease; (ii) non-cash unit-based compensation expense; (iii) income attributable to noncontrolling interests related to Buckeye for periods prior to the Merger in order to provide comparability between periods before and after the Merger; and (iv) goodwill impairment expense associated with the Natural Gas Storage segment; less (i) amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition; and (ii) gain on the sale of our equity investment in WT LPG.

The EBITDA and Adjusted EBITDA data presented may not be comparable to similarly titled measures at other companies because EBITDA and Adjusted EBITDA exclude some items that affect net income (loss) attributable to our unitholders, and these items may be defined differently by other companies. Our senior management uses Adjusted EBITDA to evaluate consolidated operating performance and the operating performance of our business segments and to allocate resources and capital to the business segments. In addition, our senior management uses Adjusted EBITDA as a performance measure to evaluate the viability of proposed projects and to determine overall rates of return on alternative investment opportunities.

We believe that investors benefit from having access to the same financial measures that we use. Further, we believe that these measures are useful to investors because they are one of the bases for comparing our operating performance with that of other companies with similar operations, although our measures may not be directly comparable to similar measures used by other companies.

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Each segment uses the same accounting policies as those used in the preparation of our consolidated financial statements. All inter-segment revenues, operating income and assets have been eliminated. All periods are presented on a consistent basis. All of our operations and assets are conducted and located in the United States, including Puerto Rico, or the Bahamas.

Financial information about each segment, EBITDA, Adjusted EBITDA and a reconciliation of EBITDA and Adjusted EBITDA to net income (loss) attributable to our unitholders, which is the most comparable GAAP financial measure (in thousands) are presented below for the periods or at the dates indicated (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenue:				
Pipelines & Terminals	$ 162,740	$ 145,521	$ 456,056	$ 424,536
International Operations (1)	47,986		146,051	
Natural Gas Storage	15,742	21,663	49,431	68,318
Energy Services	894,618	566,804	2,810,055	1,636,955
Development & Logistics	10,766	9,082	30,937	27,382
Intersegment	(14,941)	(8,213)	(45,991)	(23,884)
Total revenue	$ 1,116,911	$ 734,857	$ 3,446,539	$ 2,133,307
Depreciation and amortization:				
Pipelines & Terminals	$ 14,727	$ 11,649	$ 40,502	$ 34,346
International Operations	12,868		36,299	
Natural Gas Storage	1,807	1,643	5,326	4,924
Energy Services	1,379	1,331	3,894	3,702
Development & Logistics	449	439	1,206	1,287
Total depreciation and amortization	$ 31,230	$ 15,062	$ 87,227	$ 44,259
Operating income (loss):				
Pipelines & Terminals	$ 69,258	$ 72,647	$ 208,377	$ 209,586
International Operations	17,657		56,358	
Natural Gas Storage	(172,078)	2,795	(178,096)	9,548
Energy Services	5,415	2,581	8,940	(1,287)
Development & Logistics	2,443	1,490	5,614	3,096
Total operating income (loss)	$ (77,305)	$ 79,513	$ 101,193	$ 220,943

(1) The International Operations segment s revenue generated in The Bahamas was $53.1 million and $143.3 million for the three and nine months ended September 30, 2011, respectively, which represents 92.8% and 92.3% of the International Operations segment s total revenue for the two periods.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Adjusted EBITDA:				
Pipelines & Terminals	$ 86,510	$ 89,051	$ 260,743	$ 256,458
International Operations	30,095		86,248	
Natural Gas Storage	426	5,753	266	18,311
Energy Services	6,978	4,586	13,578	4,340
Development & Logistics	2,519	2,013	5,563	3,500
Total Adjusted EBITDA	$ 126,528	$ 101,403	$ 366,398	$ 282,609
GAAP Reconciliation:				
Net income (loss)	$ (108,200)	$ 60,962	$ 53,205	$ 165,042
Less: net income attributable to noncontrolling interests	(1,500)	(49,021)	(4,391)	(130,324)
Net income (loss) attributable to Buckeye Partners, L.P.	(109,700)	11,941	48,814	34,718
Interest and debt expense	33,199	22,082	90,292	65,088
Income tax expense (benefit)		229	(193)	(435)
Depreciation and amortization	31,230	15,062	87,227	44,259
EBITDA	(45,271)	49,314	226,140	143,630
Net income attributable to noncontrolling interests affected by Merger (for periods prior to Merger) (1)		49,150		130,205
Gain on sale of equity investment			(34,112)	
Amortization of unfavorable storage contracts (2)	(485)		(4,813)	
Non-cash deferred lease expense	1,030	1,059	3,091	3,176
Non-cash unit-based compensation expense	1,694	1,880	6,532	5,598
Goodwill impairment expense	169,560		169,560	
Adjusted EBITDA	$ 126,528	$ 101,403	$ 366,398	$ 282,609

(1) Amounts represent portions of BGH s noncontrolling interests related to Buckeye that were eliminated as a result of the Merger. Amounts are added back for the 2010 periods to provide comparability with the 2011 periods.

(2) Represents amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition.

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	Nine Months Ended September 30,	
	2011	2010
Capital additions, net: (1)		
Pipelines & Terminals	$ 61,156	$ 38,129
International Operations	122,837	
Natural Gas Storage	5,673	7,466
Energy Services	1,228	2,835
Development & Logistics	474	845
Total capital additions, net	$ 191,368	$ 49,275

(1) Amount excludes $20.1 million and $1.0 million of non-cash changes in accruals for capital expenditures for the nine months ended September 30, 2011 and 2010, respectively (see Note 22).

	September 30, 2011	December 31, 2010
Total Assets:		
Pipelines & Terminals (1)	$ 2,524,983	$ 2,328,702
International Operations (2)	1,999,967	60,313
Natural Gas Storage	365,484	549,876
Energy Services	595,242	561,382
Development & Logistics	72,254	73,943
Total assets	$ 5,557,930	$ 3,574,216
Goodwill:		
Pipelines & Terminals	$ 248,250	$ 248,250
International Operations	498,719	
Natural Gas Storage		169,560
Energy Services	1,132	1,132
Development & Logistics	13,182	13,182
Total goodwill	$ 761,283	$ 432,124

(1) All equity investments are included in the assets of the Pipelines & Terminals segment.

(2) The International Operations segment s long-lived assets consist of property, plant and equipment, goodwill, intangible assets and other non-current assets. Total long-lived assets located in or attributable to The Bahamas was $1,911.0 million at September 30, 2011, which was 97.3% of the International Operations segment s total long-lived assets.

21. RELOCATION

On August 16, 2011, we announced our plan to relocate certain corporate and operational related support functions from our Breinigsville, Pennsylvania office to our corporate headquarters located in Houston, Texas. Pursuant to the terms of the plan, approximately 50 employees will

be affected as a result of this relocation activity and will receive severance benefits, including medical and dental coverage, outplacement services and counselling. Additionally, certain employees will receive a one-time retention payment. The receipt of the severance and retention payments is contingent upon each employee working until their termination date. The relocation activities are expected to be complete by July 2013. The severance and retention bonuses are accounted for in accordance with Accounting Standards Codification (ASC) 712, *Compensation Nonretirement Postemployment Benefits* and ASC 420, *Exit or Disposal Cost Obligations*, respectively.

As of September 30, 2011, we recorded a relocation expense of $0.5 million, which was recorded in general and administrative expenses in our condensed consolidated statement of operations, for the severance and retention payments earned during the period as the liability and expense will be recognized ratably over the future service period. These relocation costs will be allocated to each business segment, except for the International Operations segment. We expect to incur expenses of $1.5 million during 2011 and $5.0 million in the aggregate through the completion of the relocation in 2013.

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BUCKEYE PARTNERS, L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

22. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flows and non-cash transactions were as follows for the periods indicated (in thousands):

	Nine Months Ended September 30,	
	2011	2010
Cash paid for interest (net of capitalized interest)	$ 101,998	$ 73,230
Cash paid for income taxes	1,104	801
Capitalized interest	5,388	1,710
Non-cash changes in assets and liabilities:		
Change in accrued and other current liabilities related to capital expenditures	$ 20,084	$ 1,028
Non-cash financing activities:		
Issuance of units to First Reserve for BORCO acquisition	$ 407,391	$
Issuance of units to Vopak for BORCO acquisition	96,110	
Issuance of Class B Units in lieu of quarterly cash distribution	20,756	

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

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this report as well as the consolidated financial statements and related notes, together with our discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K/A for the year ended December 31, 2010.

Our consolidated financial statements have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs, as well as assumptions made by us and information currently available to us. When used in this document, words such as proposed, anticipate, project, potential, could, should, continue, estimate, expect, may, believe, will, plan, seek, outlook and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we believe that such expectations reflected in such forward-looking statements are reasonable, we cannot give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A Risk Factors included in our Annual Report on Form 10-K/A for the year ended December 31, 2010. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. Although the expectations in the forward-looking statements are based on our current beliefs and expectations, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Critical Accounting Policies and Estimates

A summary of the significant accounting policies we adopted and followed in the preparation of our condensed consolidated financial statements is included in our Annual Report on Form 10-K/A for the year ended December 31, 2010. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods, estimated useful lives and disposals of property, plant and equipment; reserves for environmental matters; fair value of derivatives; measuring the fair value of goodwill; and measuring recoverability of long-lived assets and equity method investments. These estimates are based on our knowledge and understanding of current conditions and actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

As our business strategy involves expanding and diversifying our portfolio of energy assets, certain acquisitions have resulted in goodwill, which represents $761.3 million of total assets on our balance sheet at September 30, 2011. During the three months ended September 30, 2011, we concluded the continued downward performance in operating income and Adjusted EBITDA (as defined below) in the Natural Gas Storage segment due to decreases in contracted storage prices relating to low volatility in natural gas prices and compressed seasonal spreads was an impairment indicator; therefore, we performed an interim goodwill impairment test. Our Natural Gas reporting unit failed step one of the goodwill impairment test; therefore, we performed the second step. As a result of our step two analysis, we concluded goodwill in the Natural Gas segment was fully impaired and recorded a non-cash goodwill impairment charge of $169.6 million as of September 30, 2011. We considered the goodwill impairment an indicator of impairment related to the long-lived assets associated with the Natural Gas reporting unit. Accordingly, we evaluated these assets for impairment in connection with our step two analysis and concluded that no impairment of the long-lived asset existed.

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Overview of Business

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership (MLP), and its limited partnership units representing limited partner interests (LP Units) are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Buckeye GP LLC (Buckeye GP is our general partner. Buckeye GP is a wholly owned subsidiary of Buckeye GP Holdings L.P. (BGH), a Delaware limited partnership that was previously publicly traded on the NYSE prior to BGH s merger with a wholly owned subsidiary of Buckeye. As used in this Management s Discussion and Analysis of Financial Condition and Results of Operations, *we*, *us*, *our* and *Buckeye* mean Buckeye Partners, L.P. and, where th context requires, includes our subsidiaries.

We were formed in 1986 and own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 6,100 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of over 64 million barrels. In 2011, we acquired (i) the Bahamas Oil Refining Company International Limited (BORCO) terminal facility in Freeport, Grand Bahama, The Bahamas, with a total installed capacity of approximately 21.6 million barrels, (ii) 33 refined petroleum products terminals with a total storage capacity of over 10 million barrels and approximately 650 miles of refined petroleum products pipelines (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements) and (iii) a 124-mile pipeline and terminal in Bangor, Maine with approximately 140,000 barrels of storage capacity and a terminal in Portland, Maine through a 50/50 joint venture with approximately 725,000 barrels (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements). In addition, we operate and maintain approximately 3,400 miles of other pipelines under agreements with major oil and gas, petrochemical and chemical companies, and perform certain engineering and construction management services for third parties. We also own and operate a high performance natural gas storage facility in northern California, and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals.

We operate and report in five business segments: Pipelines & Terminals; International Operations; Natural Gas Storage; Energy Services; and Development & Logistics. Effective January 1, 2011, we realigned our five business segments. We combined the Pipeline Operations and Terminalling & Storage segments into one segment, the Pipelines & Terminals segment, and moved our terminal in Yabucoa, Puerto Rico, previously included as part of the Terminalling & Storage segment, to a new International Operations segment with the BORCO facility. We recast our period to period comparisons to conform to the current presentation. See Note 20 in the Notes to Unaudited Condensed Consolidated Financial Statements for a discussion of our business segments.

Our primary business objective is to provide stable and sustainable cash distributions to our unitholders, while maintaining a relatively low investment risk profile. The key elements of our strategy are to maximize utilization of our assets at the lowest cost per unit, maintain stable long-term customer relationships, operate in a safe and environmentally responsible manner, optimize, expand and diversify our portfolio of energy assets, and maintain a solid, conservative financial position and our investment-grade credit rating.

Merger

On November 19, 2010, we consummated a transaction pursuant to a plan and agreement of merger (the Merger Agreement) with our general partner, BGH, BGH s general partner and our subsidiary, Grand Ohio, LLC (Merger Sub). Pursuant to the Merger Agreement, Merger Sub was merged into BGH, with BGH as the surviving entity (the Merger). In the transaction, the incentive compensation agreement (also referred to as the incentive distribution rights) held by our general partner was cancelled, the general partner units held by our general partner (representing an approximate 0.5% general partner interest in us) were converted to a non-economic general partner interest, all of the economic interest in BGH was acquired by us and BGH unitholders received aggregate consideration of approximately 20.0 million of our LP Units.

Although titled Buckeye Partners, L.P., the accompanying 2010 financial statements in this Quarterly Report on Form 10-Q were originally the financial statements of BGH prior to the completion of the Merger. BGH is considered the surviving consolidated entity for accounting purposes, although Buckeye is the surviving consolidated entity for legal and reporting purposes. The Merger was accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger did not result in gain or loss recognition.

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Our general partner, Buckeye GP, continues to manage us following the Merger.

Recent Developments

Acquisition of BORCO

On December 18, 2010, we, through a wholly owned subsidiary, entered into a sale and purchase agreement with affiliates of FRC Founders Corporation (First Reserve), pursuant to which we agreed to acquire First Reserve s indirect 80% interest in FR Borco Coop Holdings, L.P. (FRBCH), the indirect owner of BORCO, for $1.15 billion, financed through a combination of debt and equity, including the issuance of Class B units representing limited partner interests (Class B Units) and LP Units to First Reserve. BORCO is the fourth largest oil and petroleum products storage terminal in the world and the largest petroleum products facility in the Caribbean with current storage capacity of approximately 21.6 million barrels. On January 18, 2011, we completed the purchase of First Reserve s interest in BORCO through the acquisition by us of all of the partnership interests in FR Borco Topco, L.P., which indirectly owned First Reserve s interest.

Vopak Bahamas B.V. (Vopak), which is based in The Netherlands, owned the remaining 20% interest in FRBCH. On February 16, 2001, Vopak sold its 20% interest in FRBCH to us for approximately $276.5 million of cash and equity, which is a proportionate price and on the same terms and conditions as those in the sale and purchase agreement with First Reserve.

On January 13, 2011, we issued $650.0 million aggregate principal amount of 4.875% Notes due 2021 (the 4.875% Notes) in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price of the BORCO acquisition.

On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the BORCO acquisition. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of the BORCO acquisition. Equity issuance costs incurred on these transactions were approximately $4.6 million. The remaining purchase price was funded with cash on hand at closing and borrowings under our Prior BPL Credit Facility (as defined in below).

On January 18, 2011, in connection with the BORCO acquisition, we repaid all of BORCO s outstanding indebtedness and settled BORCO s interest rate derivative instruments, collectively representing approximately $318.2 million.

For additional information, see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Equity Offering

In April 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

Sale of Interest in West Texas LPG Pipeline Limited Partnership

On May 11, 2011, we sold our 20% interest in West Texas LPG Pipeline Limited Partnership (WT LPG) to affiliates of Atlas Pipeline Partners L.P. for $85.0 million. WT LPG owns a 2,295-mile common-carrier pipeline system that transports natural gas liquids from points in New Mexico and Texas to Mont Belvieu, Texas for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WT LPG. The

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proceeds from the sale were used to fund a portion of our internal growth capital projects planned for 2011. We recognized a gain of $34.1 million on the sale of our interest in WT LPG.

Acquisition of Pipeline & Terminal Assets

On June 1, 2011, we acquired 33 refined petroleum products terminals with total storage capacity of over 10 million barrels and approximately 650 miles of refined petroleum products pipelines from BP Products North America Inc. and its affiliates (BP) for $166.0 million. The terminal and pipeline assets are located in the Midwestern, Southeastern and Western United States and we believe the acquisition of these assets further extends our operations into new, key geographic markets. The operations of these acquired assets are reported in the Pipelines & Terminals segment. We funded this acquisition with borrowings under our Prior BPL Credit Facility.

Acquisition of Refined Petroleum Products Terminals and Pipeline in Maine

On July 19, 2011, we acquired a 124-pipeline and terminal in Bangor, Maine (Bangor terminal) with approximately 140,000 barrels of storage capacity and a terminal in Portland, Maine (South Portland terminal) through a 50/50 joint venture with Irving Oil Terminals Inc. with approximately 725,000 barrels of storage capacity from an affiliate of ExxonMobil for $23.5 million in cash. The South Portland terminal is operated by our Development & Logistics segment. We accounted for the South Portland terminal using the equity method of accounting. See Note 7 in the Notes to Unaudited Condensed Consolidated Financial Statements for equity investment information. The pipeline, Bangor terminal and equity investment are reported in the Pipelines & Terminals segment. We financed this acquisition with borrowings under our Prior BPL Credit Facility.

Results of Operations

Adjusted EBITDA

Adjusted EBITDA is the primary measure used by senior management, including our Chief Executive Officer, to evaluate our operating results and to allocate our resources. We define EBITDA, a measure not defined under GAAP, as net income (loss) attributable to our unitholders before interest and debt expense, income taxes and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. The EBITDA measure eliminates the significant level of non-cash depreciation and amortization expense that results from the capital-intensive nature of our businesses and from intangible assets recognized in business combinations. In addition, EBITDA is unaffected by our capital structure due to the elimination of interest and debt expense and income taxes. We define Adjusted EBITDA, which is also a non-GAAP measure, as EBITDA plus: (i) non-cash deferred lease expense, which is the difference between the estimated annual land lease expense for our natural gas storage facility in the Natural Gas Storage segment to be recorded under GAAP and the actual cash to be paid for such annual land lease; (ii) non-cash unit-based compensation expense; (iii) income attributable to noncontrolling interests related to Buckeye for periods prior to the Merger in order to provide comparability between periods before and after the Merger; and (iv) goodwill impairment expense associated with the Natural Gas Storage segment; less (i) amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition; and (ii) gain on the sale of our equity investment in WT LPG.

The EBITDA and Adjusted EBITDA data presented may not be comparable to similarly titled measures at other companies because EBITDA and Adjusted EBITDA exclude some items that affect net income (loss) attributable to our unitholders, and these items may be defined differently by other companies. Our senior management uses Adjusted EBITDA to evaluate consolidated operating performance and the operating performance of our business segments and to allocate resources and capital to the business segments. In addition, our senior management uses Adjusted EBITDA as a performance measure to evaluate the viability of proposed projects and to determine overall rates of return on alternative investment opportunities.

We believe that investors benefit from having access to the same financial measures that we use. Further, we believe that these measures are useful to investors because they are one of the bases for comparing our operating

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performance with that of other companies with similar operations, although our measures may not be directly comparable to similar measures used by other companies.

The following table presents Adjusted EBITDA by segment and on a consolidated basis for the periods indicated, and a reconciliation of EBITDA and Adjusted EBITDA to net income (loss) attributable to our unitholders, which is the most comparable GAAP financial measure (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Adjusted EBITDA:				
Pipelines & Terminals	$ 86,510	$ 89,051	$ 260,743	$ 256,458
International Operations	30,095		86,248	
Natural Gas Storage	426	5,753	266	18,311
Energy Services	6,978	4,586	13,578	4,340
Development & Logistics	2,519	2,013	5,563	3,500
Total Adjusted EBITDA	$ 126,528	$ 101,403	$ 366,398	$ 282,609
GAAP Reconciliation:				
Net income (loss)	$ (108,200)	$ 60,962	$ 53,205	$ 165,042
Less: net income attributable to noncontrolling interests	(1,500)	(49,021)	(4,391)	(130,324)
Net income (loss) attributable to Buckeye Partners, L.P.	(109,700)	11,941	48,814	34,718
Interest and debt expense	33,199	22,082	90,292	65,088
Income tax expense (benefit)		229	(193)	(435)
Depreciation and amortization	31,230	15,062	87,227	44,259
EBITDA	(45,271)	49,314	226,140	143,630
Net income attributable to noncontrolling interests affected by Merger (for periods prior to Merger) (1)		49,150		130,205
Gain on sale of equity investment			(34,112)	
Amortization of unfavorable storage contracts (2)	(485)		(4,813)	
Non-cash deferred lease expense	1,030	1,059	3,091	3,176
Non-cash unit-based compensation expense	1,694	1,880	6,532	5,598
Goodwill impairment expense	169,560		169,560	
Adjusted EBITDA	$ 126,528	$ 101,403	$ 366,398	$ 282,609

(1) Amounts represent portions of BGH s noncontrolling interests related to Buckeye that were eliminated as a result of the Merger. Amounts are added back for the 2010 periods to provide comparability with the 2011 periods.

(2) Represents amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition.

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Segment Results

A summary of financial information by business segment follows for the periods indicated (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenues:				
Pipelines & Terminals	$ 162,740	$ 145,521	$ 456,056	$ 424,536
International Operations	47,986		146,051	
Natural Gas Storage	15,742	21,663	49,431	68,318
Energy Services	894,618	566,804	2,810,055	1,636,955
Development & Logistics	10,766	9,082	30,937	27,382
Intersegment	(14,941)	(8,213)	(45,991)	(23,884)
Total revenues	$ 1,116,911	$ 734,857	$ 3,446,539	$ 2,133,307
Total costs and expenses: (1)				
Pipelines & Terminals	$ 93,482	$ 72,874	$ 247,679	$ 214,950
International Operations	30,329		89,693	
Natural Gas Storage	187,820	18,868	227,527	58,770
Energy Services	889,203	564,223	2,801,115	1,638,242
Development & Logistics	8,323	7,592	25,323	24,286
Intersegment	(14,941)	(8,213)	(45,991)	(23,884)
Total costs and expenses	$ 1,194,216	$ 655,344	$ 3,345,346	$ 1,912,364
Depreciation and amortization:				
Pipelines & Terminals	$ 14,727	$ 11,649	$ 40,502	$ 34,346
International Operations	12,868		36,299	
Natural Gas Storage	1,807	1,643	5,326	4,924
Energy Services	1,379	1,331	3,894	3,702
Development & Logistics	449	439	1,206	1,287
Total depreciation and amortization	$ 31,230	$ 15,062	$ 87,227	$ 44,259
Operating income (loss):				
Pipelines & Terminals	$ 69,258	$ 72,647	$ 208,377	$ 209,586
International Operations	17,657		56,358	
Natural Gas Storage	(172,078)	2,795	(178,096)	9,548
Energy Services	5,415	2,581	8,940	(1,287)
Development & Logistics	2,443	1,490	5,614	3,096
Total operating income (loss)	$ (77,305)	$ 79,513	$ 101,193	$ 220,943

(1) Total costs and expenses includes depreciation and amortization.

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The following table presents product volumes transported and average daily throughput for the Pipelines & Terminals segment in barrels per day (bpd), average daily throughput for the International Operations segment and total volumes sold in gallons for the Energy Services segment for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Pipelines & Terminals (average bpd):				
Pipelines:				
Gasoline	682,600	663,900	649,100	647,400
Jet fuel	344,800	350,700	339,800	337,500
Diesel fuel	267,300	237,000	250,800	229,200
Heating oil	29,600	35,000	56,800	61,400
LPGs	15,100	16,700	17,500	19,500
Other products	4,500	3,300	7,200	2,600
Total pipelines throughput	1,343,900	1,306,600	1,321,200	1,297,600
Terminals: (1)				
Products throughput	900,100	566,200	688,600	564,200
International Operations (average bpd): (2)				
Products throughput	391,765		477,853	
Energy Services (in thousands of gallons):				
Sales volumes	297,400	278,000	960,800	780,000

(1) 2011 amounts include throughput volumes on terminals acquired from BP and ExxonMobil on June 1, 2011 and July 19, 2011, respectively.

(2) The BORCO facility was acquired on January 18, 2011, and the Yabucoa, Puerto Rico terminal was acquired on December 10, 2010.

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

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $25.1 million, or 24.8%, to $126.5 million for the three months ended September 30, 2011 from $101.4 million for the corresponding period in 2010. The International Operations segment, Energy Services segment and Development & Logistics segment were primarily responsible for the increase in Adjusted EBITDA. The International Operations segment increased Adjusted EBITDA by $30.1 million as a result of the acquisitions of BORCO and the Yabucoa, Puerto Rico terminal in January 2011 and December 2010, respectively, offset by acquisition and integration expenses. The Energy Services segment s Adjusted EBITDA increased by $2.4 million for the three months ended September 30, 2011 as compared to the corresponding period in 2010 as a result of an increase in revenue due to increased volumes of product sold and higher margins and lower operating costs. Renewable identification numbers (RIN) sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold. The Development & Logistics segment s Adjusted EBITDA increased by $0.5 million for the three months ended September 30, 2011 as compared to the corresponding period in 2010, primarily due to increased operating services contract margins as a result of new contracts and higher fees.

These increases in Adjusted EBITDA were partially offset by a decrease in Adjusted EBITDA in the Natural Gas Storage segment and the Pipelines & Terminals segment. The Natural Gas Storage segment s Adjusted EBITDA decreased by $5.4 million for the three months ended September 30, 2011 as compared to the corresponding period in 2010 resulting primarily from a decrease in the hub services margin and net lease revenue

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as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads and higher operating costs. The Pipelines & Terminals segment s Adjusted EBITDA decreased by $2.6 million for the three months ended September 30, 2011 as compared to the corresponding period in 2010 primarily due to a decrease in revenue due to lower pipeline and terminalling volumes on assets existing prior to acquisitions in 2010 (which we refer to as our legacy assets), higher cash operating expenses, unfavorable settlement experience, acquisition and integration expenses and a decrease in earnings from equity investments primarily due to the sale of our interest in one of our investments, partially offset by a positive net contribution relating to pipeline and terminal acquisitions in 2011 and 2010, higher tariff rates and terminalling fees and an increase in other revenue. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. Revenue was $1,116.9 million for the three months ended September 30, 2011, which is an increase of $382.0 million, or 52.0%, from the three months ended September 30, 2010. The increase in revenue for the three months ended September 30, 2011 as compared to the corresponding period in 2010 was caused primarily by the following:

- an increase of $327.8 million in revenue from the Energy Services segment, resulting from an overall increase in refined petroleum product prices and volumes of product sold during the three months ended September 30, 2011 as compared to the corresponding period in 2010. The 19.4 million gallon increase in sales volume resulted in an increase in revenue of approximately $39.6 million, which includes RIN sales, and the increase in the average sales price per gallon from $2.04 in the 2010 period to $3.01 in the 2011 period, or approximately $0.97 per gallon, contributed to an increase in revenue of approximately $288.2 million. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold;

- revenue of $48.0 million from the International Operations segment as the result of the BORCO acquisition in 2011 and the Puerto Rico terminal acquisition in December 2010;

- an increase of $17.2 million in revenue from the Pipelines & Terminals segment as a result of revenue relating to pipeline and terminal acquisitions in 2011 and 2010, higher tariff rates and terminalling fees and an increase in other revenue, partially offset by a decrease in lower pipeline and terminalling volumes on legacy assets and unfavorable settlement experience; and

- an increase of $1.7 million in revenue from the Development & Logistics segment, primarily due to an increase in operating services contract revenue as a result of new contracts and higher fees and an increase in project management and other revenue as a result of increased activity in the 2011 period.

The increases in revenue was partially offset by:

- a decrease of $6.0 million in revenue from the Natural Gas Storage segment, resulting primarily from a decrease in the hub services margin and net lease revenue as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads.

Total Costs and Expenses. Total costs and expenses were $1,194.2 million for the three months ended September 30, 2011, which is an increase of $538.9 million, or 82.2%, from the corresponding period in 2010. Total costs and expenses reflect:

- an increase of $326.3 million in the Energy Services segment s cost of product sales in the 2011 period as compared to the 2010 period, primarily as a result of increased refined petroleum product prices and increased volumes sold. The average cost of products sold, which includes recognition of biodiesel tax credits as a reduction to cost of sales, increased from approximately $2.01 per gallon in the 2010 period to approximately $2.97 per gallon in the 2011 period, or approximately $0.96 per gallon, resulting in an increase in cost of products sold of approximately $287.3 million, and sales volumes increased by 19.4 million gallons between the 2010 and 2011 periods, contributing $39.0 million to the increase in cost of products sold. The increase in costs and expenses were partially offset by a decrease of $0.9 million in payroll costs and

property taxes;

an increase of $168.9 million in costs and expenses for the Natural Gas Storage segment, resulting from a non-cash goodwill impairment charge, partially offset by lower hub services activities recognized as an expense;

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$30.3 million for costs and expenses for the International Operations segment as a result of operating the BORCO facility and the Puerto Rico terminal acquired in 2011 and December 2010, respectively, and acquisition and integration expenses;

an increase of $20.6 million in costs and expenses for the Pipelines & Terminals segment as a result of cash operating costs relating to pipeline and terminal acquisitions in 2011 and 2010, an increase in depreciation and amortization as a result of newly acquired assets placed in service, an increase in environmental expenses, acquisition and integration expenses, higher in integrity program expenses and an increase in property taxes;

a increase of $0.7 million in costs and expenses for the Development & Logistics segment, primarily due to an increase in operating services contract costs as a result of new contracts and an increase in ammonia line costs, partially offset by lower payroll costs and a decrease in income tax expense; and

an increase of $16.1 million in depreciation and amortization, primarily on assets acquired in the BORCO acquisition and in the pipeline and terminal assets acquisitions in 2011 and 2010.

Depreciation and amortization expense and income tax expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Gain on sale of equity method investment. On May 11, 2011, we sold our 20% interest in WT LPG for $85.0 million and recognized a gain of $34.1 million on the sale (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements).

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests was $1.5 million for the three months ended September 30, 2011 as compared to $49.0 million in the corresponding period in 2010. Noncontrolling interests represents Buckeye Pipe Line Services Company s (Services Company) equity and portions of the Sabina Pipeline and WesPac Pipelines Memphis LLC (WesPac Memphis) that are not owned by Buckeye. For the 2010 period through November 19, 2010, the date of the Merger, noncontrolling interests also included equity interests in Buckeye that were not owned by BGH. These interests were eliminated in connection with the Merger.

Net income (loss) attributable to unitholders. Net loss attributable to our unitholders was $109.7 million for the three months ended September 30, 2011 compared to net income of $11.9 million for the three months ended September 30, 2010. Interest and debt expense increased by $11.1 million for the three months ended September 30, 2011 as compared to the corresponding period in 2010, which increase was largely attributable to the issuance in January 2011 of the 4.875% Notes and higher outstanding borrowings under the BPL Credit Facilities and the BES Credit Facility (as defined below), partially offset by an increase of $1.3 million in capitalized interest, primarily as a result of the BORCO acquisition. Other revenue and expense items impacting operating income (loss) are discussed above.

For a more detailed discussion of the above factors affecting our results, see the following discussion by segment.

Pipelines & Terminals

Adjusted EBITDA. Adjusted EBITDA from the Pipelines & Terminals segment of $86.5 million for the three months ended September 30, 2011 decreased by $2.6 million, or 2.9%, from $89.1 million for the corresponding period in 2010. The decrease in Adjusted EBITDA was driven primarily by a $6.0 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets, a $4.7 million increase in cash operating expenses, a $2.0 million increase in unfavorable settlement experience, a $1.2 million increase in acquisition and integration expenses and a $1.0 million decrease in earnings from equity investments primarily due to the sale of our interest in one of our investments.

These decreases in Adjusted EBITDA were partially offset by a $8.3 million positive net contribution relating to pipeline and terminal acquisitions in 2011 and 2010, a $3.5 million increase in tariff rates and terminalling fees and a $0.5 million increase in other revenue. Cash operating expenses exclude depreciation and amortization and unit-based compensation expense, both of which are non-cash expenses and are not components of Adjusted

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EBITDA as presented in the reconciliation above. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipelines & Terminals segment was $162.7 million for the three months ended September 30, 2011, which is an increase of $17.2 million, or 11.8%, from the corresponding period in 2010. Revenue increased $21.2 million due to pipeline and terminal acquisitions in 2011, a $3.5 million benefit in higher tariff rates and terminalling fees as a result of average tariff rate increases of approximately 7.2% and 2.8% in July 2011 and April 2011, respectively, and a $0.5 million increase in other revenue.

These increases in revenue were partially offset by a $6.0 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets and $2.0 million of unfavorable settlement experience. Overall pipeline and terminalling volumes increased by 2.9% and 59.0%, respectively, as a result of pipeline and terminal acquisitions in 2011 and 2010. Excluding the impact of these acquisitions, pipeline and terminalling volumes decreased by 4.8% and 6.1%, respectively, primarily due to supply and demand interruptions resulting from severe weather conditions and refinery turnarounds.

Total Costs and Expenses. Total costs and expenses from the Pipelines & Terminals segment were $93.5 million for the three months ended September 30, 2011, which is an increase of $20.6 million, or 28.3%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to $12.9 million of cash operating costs relating to pipeline and terminal acquisitions in 2011 and 2010, a $3.1 million increase in depreciation and amortization as a result of newly acquired assets placed in service, a $2.3 million increase in environmental expenses, a $1.2 million increase in acquisition and integration expenses, a $0.6 million increase in integrity program expenses and a $0.5 million increase in property taxes. Depreciation and amortization expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Pipelines & Terminals segment was $69.3 million for the three months ended September 30, 2011 compared to operating income of $72.6 million for the three months ended September 30, 2010. Revenue and expense items impacting operating income are discussed above.

International Operations

Adjusted EBITDA. Adjusted EBITDA from the International Operations segment was $30.1 million for the three months ended September 30, 2011. The revenue and expense factors affecting Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the International Operations segment was $48.0 million for the three months ended September 30, 2011 as the result of the BORCO acquisition in 2011 and the Puerto Rico terminal acquisition in December 2010. Revenue included storage fees of $39.9 million, which represent fees charged for storage of various products, berthing fees of $4.2 million, which represent amounts charged to ships that utilize the facility s jetties, and other ancillary service revenue of $3.4 million. Also included in revenue is the recognition of $0.5 million of revenue from unfavorable storage contracts acquired in connection with the BORCO acquisition, which is not a component of Adjusted EBITDA as presented in the reconciliation above.

Total Costs and Expenses. Total costs and expenses from the International Operations segment were $30.3 million for the three months ended September 30, 2011, which included $15.7 million of costs and expenses related to operating the BORCO facility and the Yabucoa terminal, including payroll and benefits related costs, repairs and maintenance costs and lease expenses and $1.7 million in acquisition and integration expenses. Total costs and expenses also included $12.9 million of depreciation and amortization, primarily related to the depreciation of property, plant and equipment and the amortization of intangible assets (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion). Depreciation and amortization is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the International Operations segment was $17.7 million for the three months ended September 30, 2011. Revenue and expense items impacting operating income are discussed above.

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Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment was $0.4 million for the three months ended September 30, 2011 and decreased by $5.4 million, or 92.6%, from earnings of $5.8 million for the corresponding period in 2010. The decrease in Adjusted EBITDA was primarily due to a $2.7 million and $2.4 million decrease in the hub services margin and net lease revenue, respectively, as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads and a $0.3 million increase in other operating expenses during the three months ended September 30, 2011. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Natural Gas Storage segment was $15.7 million for the three months ended September 30, 2011, which is a decrease of $6.0 million, or 27.3%, from the corresponding period in 2010. Lease revenue and hub service fees are primarily determined by the difference in natural gas commodity prices for the periods in which natural gas is injected and withdrawn from the storage facility (i.e., time spread). Lease revenue decreased $2.4 million for the three months ended September 30, 2011, primarily due to a decrease in the fee charged for each volumetric unit of storage capacity leased. Market conditions resulted in a $3.6 million decrease in fees for hub service and other revenue during the three months ended September 30, 2011 as compared to the corresponding period in 2010.

Total Costs and Expenses. Total costs and expenses from the Natural Gas Storage segment were $187.8 million for the three months ended September 30, 2011, which is an increase of $168.9 million, or 895.4%, from the corresponding period in 2010. The increase primarily relates to a $169.6 million non-cash goodwill impairment charge, partially offset by a $0.7 million decrease in cost of natural gas storage services, which includes hub services fees paid to customers for hub service activities.

Operating Income (Loss). Operating loss from the Natural Gas Storage segment was $172.1 million for the three months ended September 30, 2011 compared to operating income of $2.8 million for the three months ended September 30, 2010. Revenue and expense items impacting operating income (loss) are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $7.0 million for the three months ended September 30, 2011 increased by $2.4 million, or 52.2%, from $4.6 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily due to an increase in revenue due to increased volumes of product sold and higher margins and lower operating costs. At the rack, sales volumes were 7.0% higher than in the 2010 period. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $894.6 million for the three months ended September 30, 2011, which is an increase of $327.8 million, or 57.8%, from the corresponding period in 2010. This increase in revenue was primarily due to an increase in refined petroleum product average sales prices of approximately $0.97 per gallon (average sales price per gallon was $3.01 and $2.04 for the 2011 and 2010 periods, respectively) resulting in an increase of $288.2 million in the 2011 period, and an increase of 7.0% in sales volumes that contributed an additional $39.6 million in revenue, which includes RIN sales of $3.1 million. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $889.2 million for the three months ended September 30, 2011, which is an increase of $325.0 million, or 57.6%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to a $326.3 million increase in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product

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prices (average cost of product sold per gallon, which includes recognition of biodiesel tax credits of $1.1 million recorded as a reduction to cost of sales, was $2.97 and $2.01 for the 2011 and 2010 periods, respectively). The increase in the cost of product sold between the 2010 and 2011 periods was due to the 7.0% increase in sales volumes, and the $0.96 per gallon increase in product sales price was $39.0 million and $287.3 million, respectively. These increases in total costs and expenses were partially offset by a $1.0 million decrease in payroll costs and a $0.3 million decrease in property taxes.

Operating Income. Operating income from the Energy Services segment was $5.4 million for the three months ended September 30, 2011 compared to operating income of $2.6 million for the three months ended September 30, 2010. Revenue and expense items impacting operating income are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $2.5 million for the three months ended September 30, 2011 increased by $0.5 million, or 25.1%, from $2.0 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily due to a $0.5 million increase in operating services contract margins as a result of new contracts and higher fees. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment was $10.8 million for the three months ended September 30, 2011, which is an increase of $1.7 million, or 18.5%, from the corresponding period in 2010. The increase in revenue was primarily due to a $1.5 million increase in operating services contract revenue as a result of new contracts and higher fees and a $0.2 million increase in project management and other revenue as a result of increased activity.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $8.3 million for the three months ended September 30, 2011, which is an increase of $0.7 million, or 9.6%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to a $1.0 million increase in operating services contract costs as a result of new contracts and a $0.1 million increase in ammonia line costs, partially offset by $0.2 million of lower payroll costs and a $0.2 million decrease in income tax expense in the 2011 period, which is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Development & Logistics segment was $2.4 million for the three months ended September 30, 2011 compared to operating income of $1.5 million for the three months ended September 30, 2010. Revenue and expense items impacting operating income are discussed above.

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

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $83.8 million, or 29.6%, to $366.4 million for the nine months ended September 30, 2011 from $282.6 million for the corresponding period in 2010. The International Operations segment, Energy Services segment, Pipelines & Terminals segment and Development & Logistics segment were responsible for the increase in Adjusted EBITDA. The International Operations segment increased Adjusted EBITDA by $86.2 million as a result of the acquisitions of BORCO and the Yabucoa, Puerto Rico terminal in January 2011 and December 2010, respectively, offset by acquisition and integration expenses. The Energy Services segment s Adjusted EBITDA increased by $9.3 million for the nine months ended September 30, 2011 as compared to the corresponding period in 2010 as a result of an increase in revenue due to increased volumes of product sold and higher margins and lower operating costs. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold. The Pipelines & Terminals segment s Adjusted EBITDA increased by $4.2 million for the nine months ended September 30, 2011 as compared to the corresponding period in 2010 as a result of a positive net contribution relating to pipeline and terminal acquisitions in 2011 and 2010, higher tariff rates and terminalling fees, and an increase in other revenue, partially offset by a decrease in revenue due to lower pipeline and terminalling volumes on legacy assets,

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acquisition and integration expenses, higher cash operating expenses and a decrease in earnings from equity investments primarily due to the sale of our interest in one of our investments. The Development & Logistics segment s Adjusted EBITDA increased by $2.1 million for the nine months ended September 30, 2011 as compared to the corresponding period in 2010, primarily due to expenses associated with a customer bankruptcy in the 2010 period, increased operating services contract margins as a result of new contracts and higher fees and increased project management margins, partially offset by the sale of an ammonia linefill in the 2010 period and higher operating costs.

These increases in Adjusted EBITDA were partially offset by a decrease in Adjusted EBITDA in the Natural Gas Storage segment. The Natural Gas Storage segment s Adjusted EBITDA decreased by $18.0 million for the nine months ended September 30, 2011 as compared to the corresponding period in 2010, resulting primarily from a decrease in the hub services margin and net lease revenue as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads and higher operating costs. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. Revenue was $3,446.5 million for the nine months ended September 30, 2011, which is an increase of $1,313.2 million, or 61.6%, from the nine months ended September 30, 2010. The increase in revenue for the nine months ended September 30, 2011 as compared to the corresponding period in 2010 was caused primarily by the following:

- an increase of $1,173.1 million in revenue from the Energy Services segment, resulting from an overall increase in refined petroleum product prices and volumes of product sold during the nine months ended September 30, 2011 as compared to the corresponding period in 2010. The 180.8 million gallon increase in sales volume resulted in an increase in revenue of approximately $379.5 million, which includes RIN sales, and the increase in the average sales price per gallon from $2.10 in the 2010 period to $2.92 in the 2011 period, or approximately $0.82 per gallon, contributed to an increase in revenue of approximately $793.6 million. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold;

- revenue of $146.1 million from the International Operations segment as the result of the BORCO acquisition in 2011 and the Puerto Rico terminal acquisition in December 2010;

- an increase of $31.6 million in revenue from the Pipelines & Terminals segment as a result of revenue relating to pipeline and terminal acquisitions in 2011 and 2010, higher tariff rates and terminalling fees and an increase in other revenue, partially offset by a decrease in revenue due to lower pipeline and terminalling volumes on legacy assets; and

- an increase of $3.5 million in revenue from the Development & Logistics segment, primarily due to an increase in operating services contract revenue as a result of new contracts and higher fees and an increase in project management and other revenue as a result of increased activity, partially offset by the sale of an ammonia linefill in the 2010 period.

The increase in revenue was partially offset by:

- a decrease of $18.9 million in revenue from the Natural Gas Storage segment, resulting primarily from a decrease in the hub services margin and net lease revenue as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads.

Total Costs and Expenses. Total costs and expenses were $3,345.3 million for the nine months ended September 30, 2011, which is an increase of $1,432.9 million, or 74.9%, from the corresponding period in 2010. Total costs and expenses reflect:

- an increase of $1,165.6 million in the Energy Services segment s cost of product sales in the 2011 period as compared to the 2010 period, primarily as a result of increased refined petroleum product prices and increased volumes sold. The average cost of products sold, which includes recognition of biodiesel tax credits recorded as a reduction in cost of sales, increased from approximately $2.08 per gallon in the 2010 period to approximately $2.90 per gallon in the 2011 period, or approximately

$0.82

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per gallon, resulting in an increase in cost of products sold of approximately $790.2 million, and sales volumes increased by 180.8 million gallons between the 2010 and 2011 periods, contributing $375.4 million to the increase in cost of products sold. The increase in total costs and expenses was partially offset by a decrease in payroll costs and property taxes;

an increase of $168.7 million in costs and expenses for the Natural Gas Storage segment, primarily from a non-cash goodwill impairment charge, increase in outside services and other costs and an increase in depreciation and amortization, partially offset by lower hub services transactions recognized as an expense, a decrease in payroll costs and a decrease in maintenance costs;

$89.7 million of costs and expenses for the International Operations segment as a result of operating the BORCO facility and the Puerto Rico terminal acquired in 2011 and December 2010, respectively, and acquisition and integration expenses;

an increase of $32.7 million in costs and expenses for the Pipelines & Terminals segment as a result of cash operating costs relating pipeline and terminal acquisitions in 2011 and 2010, an increase in depreciation and amortization, acquisition and integration expenses, higher integrity program expenses, an increase in environmental expenses and an increase in payroll costs, partially offset by a decrease in bad debt expense, operating power costs and other expenses;

an increase of $1.0 million in costs and expenses for the Development & Logistics segment, primarily due to an increase in operating services contract costs as a result of new contracts, higher operating costs and lower income tax benefit, partially offset expenses associated with a customer bankruptcy in the 2010 period and lower payroll costs; and

an increase of $42.9 million in depreciation and amortization, primarily on assets acquired in the BORCO acquisition and in the pipeline and terminal assets acquisitions in 2011 and 2010.

Depreciation and amortization expense and income tax expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Gain on sale of equity method investment. On May 11, 2011, we sold our 20% interest in WT LPG and recognized a gain of $34.1 million on the sale.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests was $4.4 million for the nine months ended September 30, 2011 as compared to $130.3 million in the corresponding period in 2010. Noncontrolling interests represents Services Company equity and portions of the Sabina Pipeline and WesPac Memphis that are not owned by Buckeye. The 2011 amount includes $1.7 million of noncontrolling interests expense related to the 20% of BORCO not acquired by us until February 16, 2011. For the 2010 period through November 19, 2010, the date of the Merger, noncontrolling interests also included equity interests in Buckeye that were not owned by BGH. These interests were eliminated in connection with the Merger.

Net income attributable to unitholders. Net income attributable to our unitholders was $48.8 million for the nine months ended September 30, 2011 compared to $34.7 million for the nine months ended September 30, 2010. Interest and debt expense increased by $25.2 million for the nine months ended September 30, 2011 as compared to the corresponding period in 2010, which increase was largely attributable to the issuance in January 2011 of the 4.875% Notes and higher outstanding borrowings under the BPL Credit Facilities and the BES Credit Facility, partially offset by an increase of $3.7 million in capitalized interest, primarily as a result of the BORCO acquisition. Other revenue and expense items impacting operating income are discussed above.

For a more detailed discussion of the above factors affecting our results, see the following discussion by segment.

Pipelines & Terminals

Adjusted EBITDA. Adjusted EBITDA from the Pipelines & Terminals segment of $260.7 million for the nine months ended September 30, 2011 increased by $4.2 million, or 1.7%, from $256.5 million for the corresponding period in 2010. The increase in Adjusted EBITDA was as primarily due to a $11.5 million positive net contribution relating to pipeline and terminal acquisitions in 2011 and 2010, a $11.5 million

increase in tariff rates and terminalling fees and a $3.2 million increase in other revenue.

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These increases in Adjusted EBITDA were partially offset by a $9.9 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets, a $5.7 million increase in acquisition and integration expenses, a $5.4 million increase in cash operating expenses and a $1.0 million decrease in earnings from equity investments primarily due to the sale of our interest in one of our investments. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipelines & Terminals segment was $456.1 million for the nine months ended September 30, 2011, which is an increase of $31.6 million, or 7.4%, from the corresponding period in 2010. Revenue increased by $28.0 million due to pipeline and terminal acquisitions in 2011, a $11.5 million benefit in higher tariff rates and terminalling fees due to average tariff rate increases of approximately 7.2%, 2.8% and 2.6% in July 2011, April 2011 and May 2010, respectively, and a $3.3 million increase in other revenue.

These increases in revenue were partially offset by a $9.9 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets and a $1.3 million decrease due to operating services contract revenue assigned to the Development & Logistics segment. Overall pipeline and terminalling volumes increased by 1.8% and 22.0%, respectively, as a result of the acquisition of pipeline and terminal assets in 2011 and 2010. Excluding the impact of the acquisitions, pipeline and terminalling volumes decreased by 1.5% and 7.7%, respectively, primarily due to supply and demand interruptions resulting from severe weather conditions and refinery turnarounds.

Total Costs and Expenses. Total costs and expenses from the Pipelines & Terminals segment were $247.7 million for the nine months ended September 30, 2011, which is an increase of $32.7 million, or 15.2%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to $16.5 million of cash operating costs relating to pipeline and terminal acquisitions in 2011 and 2010, a $6.2 million increase in depreciation and amortization as a result of newly acquired assets placed in service, a $5.7 million increase in acquisition and integration expenses, a $3.2 million increase in environmental expenses, a $3.2 million increase in payroll costs and a $1.9 million increase in integrity program expenses. Depreciation and amortization expense are not components of Adjusted EBITDA as presented in the reconciliation above.

These increases in total costs and expenses were partially offset by a $1.7 million decrease in operating power costs, a $1.3 million decrease in operating services contract costs assigned to the Development & Logistics segment and a $1.0 million increase in other expenses, primarily relating to bad debt expense.

Operating Income. Operating income from the Pipelines & Terminals segment was $208.4 million for the nine months ended September 30, 2011 compared to operating income of $209.6 million for the nine months ended September 30, 2010. Revenue and expense items impacting operating income are discussed above.

International Operations

Adjusted EBITDA. Adjusted EBITDA from the International Operations segment was $86.2 million for the nine months ended September 30, 2011. The revenue and expense factors affecting Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the International Operations segment was $146.1 million for the nine months ended September 30, 2011 as the result of the BORCO acquisition in 2011 and the Puerto Rico terminal acquisition in December 2010. Revenue included storage fees of $114.5 million, which represent fees charged for storage of various products, berthing fees of $13.9 million, which represent amounts charged to ships that utilize the facility s jetties, and other ancillary service revenue of $12.9 million. Also included in revenue is the recognition of $4.8 million of revenue from unfavorable storage contracts acquired in connection with the BORCO acquisition, which is not a component of Adjusted EBITDA as presented in the reconciliation above.

Total Costs and Expenses. Total costs and expenses from the International Operations segment were $89.7 million for the nine months ended September 30, 2011, which included $46.7 million of costs and expenses related to operating the BORCO facility and the Yabucoa terminal, including payroll and benefits related costs, repairs and maintenance costs and lease expenses and $6.7 million in acquisition and integration expenses. Total costs and expenses also included $36.3 million of depreciation and amortization, primarily related to the depreciation of

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property, plant and equipment and the amortization of intangible assets (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion). Depreciation and amortization is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the International Operations segment was $56.4 million for the nine months ended September 30, 2011. Revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment was $0.3 million for the nine months ended September 30, 2011 and decreased by $18.0 million, or 98.5%, from earnings of $18.3 million for the corresponding period in 2010. The decrease in Adjusted EBITDA was primarily the result of a $9.3 million and $6.3 million decrease in hub services margin and net lease revenue, respectively, as a result of decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads and a $2.4 million increase in other operating expenses during the nine months ended September 30, 2011. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Natural Gas Storage segment was $49.4 million for the nine months ended September 30, 2011, which is a decrease of $18.9 million, or 27.6%, from the corresponding period in 2010. Lease revenue and hub service fees are primarily determined by the difference in natural gas commodity prices for the periods in which natural gas is injected and withdrawn from the storage facility (i.e., time spread). Market conditions resulted in a $12.6 million decrease in fees for hub service activities during the nine months ended September 30, 2011 as compared to the corresponding period in 2010. Lease revenue decreased $6.3 million for the nine months ended September 30, 2011, primarily due to a decrease in the fee charged for each volumetric unit of storage capacity leased.

Total Costs and Expenses. Total costs and expenses from the Natural Gas Storage segment were $227.5 million for the nine months ended September 30, 2011, which is an increase of $168.7 million, or 287.1%, from the corresponding period in 2010. The increase primarily relates to a $169.6 million non-cash goodwill impairment charge, a $2.6 million increase in outside services and other costs, primarily due to well workover costs in the current period and a $0.4 million increase in depreciation and amortization, partially offset by a $3.2 million decrease in cost of natural gas storage services, which includes hub services fees paid to customers for hub service activities, a $0.5 million decrease in payroll costs and a $0.2 million decrease in maintenance costs. Depreciation and amortization are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (Loss). Operating loss from the Natural Gas Storage segment was $178.1 million for the nine months ended September 30, 2011 compared to operating income of $9.5 million for the nine months ended September 30, 2010. Revenue and expense items impacting operating income (loss) are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $13.6 million for the nine months ended September 30, 2011 increased by $9.3 million, or 212.9%, from $4.3 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily due to increased volumes of product sold and higher margins and lower expenses. At the rack, sales volumes were 23.2% higher than in the 2010 period. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $2,810.1 million for the nine months ended September 30, 2011, which is an increase of $1,173.1 million, or 71.7%, from the corresponding period in 2010. This increase in revenue was primarily due to an increase in refined petroleum product average sales prices of approximately $0.82 per gallon (average sales price per gallon was $2.92 and $2.10 for the 2011 and 2010 periods, respectively) resulting in an increase of $793.6 million in the 2011 period, and an increase of 23.2% in sales

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volumes that contributed an additional $379.5 million in revenue, which includes RIN sales of $7.7 million. RIN sales, which represent by-products of biofuels that have been blended into finished gasoline or diesel products, are included in the increased volumes of product sold.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $2,801.1 million for the nine months ended September 30, 2011, which is an increase of $1,162.9 million, or 71.0%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to an $1,165.6 million increase in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product prices (average cost of product sold per gallon, which includes recognition biodiesel tax credits of $4.7 million recorded as a reduction in cost of sales, was $2.90 and $2.08 for the 2011 and 2010 periods, respectively). The increase in the cost of product sold between the 2010 and 2011 periods was due to the 23.2% increase in sales volumes, and the $0.82 per gallon increase in product sales price was $375.4 million and $790.2 million, respectively. These increases in total costs and expenses were partially offset by a $1.4 million decrease in bad debt expense and a $1.3 million decrease in payroll costs.

Operating Income (Loss). Operating income from the Energy Services segment was $8.9 million for the nine months ended September 30, 2011 compared to operating loss of $1.3 million for the nine months ended September 30, 2010. Revenue and expense items impacting operating income (loss) are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $5.6 million for the nine months ended September 30, 2011 increased by $2.1 million, or 58.9%, from $3.5 million for the corresponding period in 2010, primarily due to a $2.4 million increase in expenses associated with a customer bankruptcy in the 2010 period, a $1.1 million increase in operating services contract margins as a result of new contracts and higher fees and a $0.2 million increase in project management margins, partially offset by the $1.1 million sale of an ammonia linefill in the 2010 period and $0.5 million of higher operating costs. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment was $30.9 million for the nine months ended September 30, 2011, which is an increase of $3.5 million, or 13.0%, from the corresponding period in 2010. The increase in revenue was primarily due to a $4.1 million increase in operating services contract revenue as a result of new contracts and higher fees and a $0.5 million increase in project management and other revenue as a result of increased activity, partially offset by the $1.1 million sale of an ammonia linefill in the 2010 period.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $25.3 million for the nine months ended September 30, 2011, which is an increase of $1.0 million, or 4.3%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to a $3.0 million increase in operating services contract costs as a result of new contracts, $0.5 million of higher operating costs and $0.2 million of lower income tax benefit, partially offset by $2.4 million of expenses associated with a customer bankruptcy in the 2010 period and $0.3 million of lower payroll costs. The income tax benefit is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Development & Logistics segment was $5.6 million for the nine months ended September 30, 2011 compared to operating income of $3.1 million for the nine months ended September 30, 2010. Revenue and expense items impacting operating income are discussed above.

Liquidity and Capital Resources

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. Our principal sources of liquidity are cash from operations, borrowings under our Credit Facility and proceeds from the issuance of our units. We will, from time to time, issue debt securities to permanently finance amounts borrowed under our Credit

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Facility. Buckeye Energy Services LLC (BES) funds its working capital needs principally from its operations and its portion of the Credit Facility. Our financial policy has been to fund sustaining capital expenditures with cash from operations. Expansion and cost improvement capital expenditures, along with acquisitions, have typically been funded from external sources including our BPL Credit Facilities as well as debt and equity offerings. Our goal has been to fund at least half of these expenditures with proceeds from equity offerings in order to maintain our investment-grade credit rating.

In 2011, we completed the purchase of First Reserve s and Vopak s interests in FRBCH, the indirect owner of BORCO, for approximately $1.4 billion in cash and equity. We also assumed BORCO s outstanding indebtedness and settled BORCO s interest rate derivative instruments, collectively representing approximately $318.2 million. In order to fund a portion of the combined purchase price and the repayment of BORCO s indebtedness, in January 2011, we issued a $650.0 million of our 4.875% Notes due 2021. The notes were issued at 99.62% of their principal amount. In addition, in January 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million. The proceeds from the debt offering and these equity issuances were used to fund a portion of the BORCO acquisition. The remaining purchase price for the BORCO acquisition and the repayment of the assumed debt was funded through the issuance of LP Units and Class B Units to both First Reserve and Vopak, cash on hand and borrowings under our Prior BPL Credit Facility.

In April 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

In June 2011, we acquired pipelines and terminal assets from BP for $166.0 million, and in July 2011, we acquired a 124-pipeline and terminal in Bangor, Maine and a terminal in Portland, Maine through a 50/50 joint venture with Irving Oil Inc. from ExxonMobil for $23.5 million. As a result of our actions in 2011 and that no debt obligations mature prior to 2013, we believe that availabilities under our Credit Facility, coupled with ongoing cash flows from operations, will be sufficient to fund our operations for the remainder of 2011, including any expansion plans for the BORCO terminal facility. In addition, we used the proceeds from the sale of WT LPG to fund a portion of our internal growth capital projects planned for 2011. We will continue to evaluate a variety of financing sources, including the debt and equity markets described above throughout 2011.

Debt

At September 30, 2011, we had $16.2 million of cash and cash equivalents on hand and approximately $626.2 million of available credit under the Credit Facility, after application of the facility s funded debt ratio covenant.

At September 30, 2011, we had an aggregate face amount of $2,667.5 million of debt, which consisted of the following:

$300.0 million of 4.625% Notes due 2013 (the 4.625% Notes);

$275.0 million of 5.300% Notes due 2014 (the 5.300% Notes);

$125.0 million of 5.125% Notes due 2017 (the 5.125% Notes);

$300.0 million of 6.050% Notes due 2018 (the 6.050% Notes);

$275.0 million of 5.500% Notes due 2019 (the 5.500% Notes);

$650.0 million of 4.875% Notes due 2021;

$150.0 million of 6.750% Notes due 2033 (the 6.750% Notes); and

$592.5 million outstanding under the Credit Facility.

See Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements for more information about the terms of the debt discussed above.

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On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price for our acquisition of BORCO. See Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion of the BORCO acquisition.

On January 18, 2011, in connection with the BORCO acquisition, we assumed BORCO s outstanding indebtedness and settled BORCO s interest rate derivative instruments, collectively representing approximately $318.2 million.

On September 26, 2011, Buckeye and its indirect wholly-owned subsidiary, Buckeye Energy Services LLC (BES), as borrowers, entered into a Revolving Credit Agreement (the Credit Facility) with SunTrust Bank, as administrative agent and other lenders to provide for a $1.25 billion senior unsecured revolving credit agreement of which we have a borrowing capacity of $1.25 billion and BES has a sublimit of $500.0 million. The Credit Facility s maturity date is September 26, 2016, with an option to extend the term for two successive one-year periods and a $500.0 million accordion option to increase the commitments. Concurrently with the execution of the Credit Facility, Buckeye and BES borrowed $243.7 million and $318.8 million, respectively, and used the proceeds to repay all amounts outstanding under Buckeye s senior unsecured revolving credit agreement dated November 13, 2006 (Prior BPL Credit Facility) and BES s amended and restated senior revolving credit agreement dates as of June 25, 2010 (BES Credit Facility), respectively, and customary fees and expenses related to the Credit Facility.

Under the Credit Facility, interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the applicable borrower for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the credit ratings assigned to our senior unsecured long-term debt securities. The applicable margin for LIBOR rate loans, swing line loans, and letter of credit fees ranges from 1.0% to 1.75% and the applicable margin for base rate loans ranges from 0% to 0.75%. The borrowers will also pay a fee based on our credit ratings on the actual daily unused amount of the aggregate commitments.

At September 30, 2011 and December 31, 2010, Buckeye had $592.5 million and $98.0 million, respectively, and BES had $0 million and $284.3 million, respectively, outstanding under their respective credit agreements. The BES outstanding balances were classified as current liabilities in our condensed consolidated balance sheets as related funds were used to finance current working capital needs. The fair values of our aggregate debt and credit facilities were estimated to be $2,789.0 million and $1,897.5 million at September 30, 2011 and December 31, 2010, respectively. The fair values of the fixed-rate debt were estimated by observing market trading prices and by comparing the historic market prices of our publicly-issued debt with the market prices of other MLPs publicly-issued debt with similar credit ratings and terms. The fair values of our variable-rate debt are their carrying amounts, as the carrying amount reasonably approximates fair value due to the variability of the interest rates.

Equity

On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the acquisition of First Reserve s 80% interest in BORCO. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of the acquisition of Vopak s 20% interest in BORCO. Equity issuance costs incurred on these transactions were approximately $4.6 million.

As discussed above, in April 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

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Registration Statement

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) that does not place any dollar limits on the amount of debt and equity securities that we may issue thereunder.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (in thousands):

	Nine Months Ended September 30,	
	2011	**2010**
Cash provided by (used in):		
Operating activities	$ 182,062	$ 296,107
Investing activities	(1,191,429)	(41,608)
Financing activities	1,011,937	(276,151)

Operating Activities

Net cash flows provided by operating activities was $182.1 million for the nine months ended September 30, 2011 compared to $296.1 million for the nine months ended September 30, 2010. The following were the principal factors impacting net cash flows provided by operating activities for the nine months ended September 30, 2011:

We recorded a $169.6 million goodwill impairment expense relating to the Natural Gas Storage segment.

The net change in fair values of derivatives was a decrease of $150.4 million to cash flows from operating activities for the nine months ended September 30, 2011, resulting from the decrease in value related to futures contracts executed to hedge physical inventory. The offsetting adjustment is made to the value of inventory by adjusting inventory to current market prices.

The net impact of working capital changes was a decrease of $40.3 million to cash flows from operating activities for the nine months ended September 30, 2011. The principal factors affecting working capital changes were:

Other non-current liabilities increased by $81.6 million due to an increase in derivative liabilities.

Other non-current assets increased by $11.7 million due to a decrease in prepaid services, long-term derivative assets, unbilled revenue and insurance receivables.

Inventories increased by $9.6 million due to an increase in inventory purchases within the Energy Services segment.

Accrued and other current liabilities decreased by $36.7 million primarily due to a decrease in accrued interest as a result of interest payments made during the period, a decrease in unearned revenue primarily in the Natural Gas Storage segment as a result of decreased hub services activities during the period and a decrease in customer deposits.

Trade receivables decreased by $0.9 million due to the timing of collections from customers.

Accounts payable decreased by $3.7 million due to lower payable balances at September 30, 2011 as a result of the timing of invoice payments.

Construction and pipeline relocation receivables decreased by $0.6 million primarily due to a decrease in construction activity in the 2011 period.

Prepaid and other current assets decreased by $8.1 million primarily due to a decrease in margin deposits on futures contracts in our Energy Services segment as a result of increased commodity prices during the nine months ended September 30, 2011 (increased commodity prices result in an increase in our broker equity account and therefore less margin deposit is

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required) and a decrease in prepaid expenses due to lower expense contracts in the Natural Gas Storage segment as a result of decreased hub services activities.

Investing Activities

Net cash flows used in investing activities was $1,191.4 million for the nine months ended September 30, 2011 compared to $41.6 million for the nine months ended September 30, 2010. The following were the principal factors resulting in the $1,149.8 million increase in net cash flows used in investing activities:

Capital expenditures increased by $142.1 million for the nine months ended September 30, 2011 compared with the nine months ended September 30, 2010. See below for a discussion of capital spending.

We completed the acquisition of BORCO by purchasing interests from First Reserve and Vopak on January 18, 2011 and February 16, 2011, respectively, for approximately $1.4 billion of total consideration, consisting of $893.7 million in cash, which is net of cash acquired of $27.0 million. The remaining consideration of $503.5 million consisted of the issuance of LP Units and Class B Units. See Financing Activities below for a discussion of the repayment of BORCO s outstanding indebtedness, which occurred in connection with the BORCO acquisition. See Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion regarding the BORCO acquisition.

We acquired pipeline and terminal assets from BP and a pipeline, terminal and equity investment from ExxonMobil for approximately $166.0 million and $23.5 million, respectively. See Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion.

We received cash proceeds from the sale of our 20% interest in WT LTP of $85.0 million during the nine months ended September 30, 2011. Cash proceeds from the sale of the Buckeye NGL Pipeline were $22.0 million during the nine months ended September 30, 2010.

Capital expenditures, net of non-cash changes in accruals for capital expenditures, were as follows for the periods indicated (in thousands):

	Nine Months Ended September 30,	
	2011	**2010**
Sustaining capital expenditures	$ 36,569	$ 18,513
Expansion and cost reduction	154,799	30,762
Total capital expenditures, net	$ 191,368	$ 49,275

Expansion and cost reduction projects in the first nine months of 2011 included upgrades and expansions of a jetty structure and inland dock at BORCO, terminal ethanol and butane blending, new pipeline connections, new natural gas storage wells, continued progress on a new pipeline and terminal billing system as well as various other operating infrastructure projects. In the first nine months of 2010, expansion and cost reduction projects included terminal ethanol and butane blending, new pipeline connections, natural gas storage well recompletions, continued progress on a new pipeline and terminal billing system as well as various other pipeline and terminal operating infrastructure projects.

We expect to spend approximately $290.0 million to $340.0 million for capital expenditures in 2011, of which approximately $50.0 million to $60.0 million is expected to relate to sustaining capital expenditures and $240.0 million to $280.0 million is expected to relate to expansion and cost reduction projects. Approximately $185.0 million to $220.0 million of these amounts are related to capital expenditures in 2011 for the BORCO facility, of which $170.0 million to $200.0 million is expected to relate to expansion projects and $15.0 million to $20.0 million is expected to relate to sustaining capital expenditures. Approximately $105.0 million to $120.0 million of these amounts are related to capital expenditures in 2011 for our other assets, excluding the BORCO facility, of which $70.0 million to $80.0 million is expected to relate to expansion projects and $35.0 million to $40.0 million is expected to relate to sustaining capital expenditures. Sustaining capital expenditures

include renewals and

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replacement of pipeline sections, tank floors and tank roofs and upgrades to station and terminalling equipment, field instrumentation and cathodic protection systems. Major expansion and cost reduction expenditures in 2011 will include upgrades and expansions of a jetty structure, inland dock and berth developments and terminal storage tank expansion projects at the BORCO facility, completion of additional storage tanks in the Midwest, the refurbishment of storage tanks and facilities in the Northeast, installation of vapor recovery units throughout our system of terminals, new injection and withdrawal wells at our natural gas storage facilities and various upgrades and expansions of our ethanol business. Cost reduction expenditures improve operational efficiencies or reduce costs.

Financing Activities

Net cash flows provided by financing activities was $1,011.9 million for the nine months ended September 30, 2011 compared to net cash flows used in financing activities of $276.2 million for the nine months ended September 30, 2010. The following were the principal factors resulting in the $1,288.1 million increase in net cash flows provided by financing activities:

We borrowed $1,100.2 million and $175.9 million and repaid $952.5 million and $233.9 million under the BPL Credit Facilities during the nine months ended September 30, 2011 and 2010, respectively. We incurred $3.6 million of debt issuance costs during the nine months ended September 30, 2011 associated with the Credit Facility entered into during September 2011.

We repaid $318.2 million of debt assumed in the BORCO acquisition, which includes settlement of BORCO s interest rate derivative instruments (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements).

We repaid $1.5 million and $4.6 million under the Services Company 3.60% Senior Secured Notes (the 3.60% ESOP Notes) during the nine months ended September 30, 2011 and 2010, respectively. We repaid the 3.60% ESOP Notes in full in March 2011.

We made net borrowings of $62.5 million and $28.0 million during the nine months ended September 30, 2011 and 2010, respectively, under the BES Credit Facility and the BES portion of the Credit Facility. We incurred $1.4 million of debt issuance costs during the nine months ended September 30, 2011 associated with the BES portion of the Credit Facility entered into during September 2011 as compared to $3.2 million of debt issuance costs during the nine months ended September 30, 2010 related to an amendment to the BES Credit Facility in June 2010.

We received $647.5 million from the issuance in January 2011 of $650.0 million in aggregate principal amount of the 4.875% Notes in an underwritten public offering. Debt issuance costs incurred were $10.0 million. Proceeds from this offering were used to fund a portion of the BORCO acquisition. In connection with this debt offering, we settled a treasury lock agreement, which resulted in the receipt of $0.5 million that is being amortized into interest expense over the ten-year term of the 4.875% Notes.

We received total proceeds of $425.0 million from the issuance of 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors in January 2011 to fund a portion of the BORCO acquisition. Equity issuance costs incurred in these equity transactions were approximately $4.6 million. We received $316.6 million in net proceeds from an underwritten equity offering in April 2011 for the public issuance of 5,520,000 LP Units.

We received $2.2 million and $4.3 million in net proceeds from the exercise of LP Unit options during the nine months ended September 30, 2011 and 2010, respectively.

We paid $1.4 million and $4.5 million of costs associated with the Merger during the nine months ended September 30, 2011 and 2010, respectively. The 2011 amount includes a payment for the settlement of litigation associated with the Merger.

Cash distributions paid to our partners were $250.2 million ($1.9875 per LP Unit) for the nine months ended September 30, 2011. Cash distributions paid to partners of BGH were $36.5 million ($0.84 per unit) for the nine months ended September 30, 2010. In connection with the Merger, BGH s units were converted into Buckeye LP Units.

Distributions to noncontrolling partners of Buckeye, consisting primarily of distributions paid by the Sabina Pipeline and WesPac Memphis, were $4.3 million for the nine months ended September 30, 2011. Distributions to noncontrolling partners of Buckeye, consisting primarily of distributions to

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holders of LP Units, were $145.5 million for the nine months ended September 30, 2010. Included in this amount was approximately $2.4 million of distributions paid primarily by the Sabina Pipeline and WesPac Memphis. Buckeye paid cash distributions of $1.8875 per LP Unit in the 2010 period. In connection with the Merger, the majority of noncontrolling interests were eliminated.

Derivatives

See Item 3. Quantitative and Qualitative Disclosures About Market Risk Market Risk Non Trading Instruments for a discussion of commodity derivatives used by our Energy Services segment.

Other Considerations

Contractual Obligations

The following table summarizes our contractual obligations as of September 30, 2011 (in thousands):

	Payments Due by Period (1)				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (2)	$ 2,320,700	$	$ 300,000	$ 275,000	$ 1,745,700
Interest payments (3)	931,027	62,566	215,921	188,446	464,094
Operating leases: (4)					
Office space and other (5)	28,022	509	4,900	5,413	17,200
Equipment (6)	10,065	877	7,095	2,093	
Land leases (7)	379,988	1,167	9,907	10,324	358,590
Purchase obligations (8)	123,688	123,688			
Capital expenditure obligations (9)	22,116	22,116			
Total contractual cash obligations	$ 3,815,606	$ 210,923	$ 537,823	$ 481,276	$ 2,585,584

(1) Less than 1 year represents amounts for the remainder of 2011 (October 1 through December 31), 1-3 years represents amounts for 2012 and 2013, 3-5 years represents amounts for 2014 and 2015, and more than 5 years represents amounts after 2015.

(2) We have long-term payment obligations under our Credit Facility and our underwritten publicly issued notes. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. We have assumed that the borrowings under our Credit Facility as of September 30, 2011 will not be repaid until the maturity date of the facility. See Note 11 in the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding our debt obligations.

(3) Interest payments include amounts due on our notes and interest payments and commitment fees due on our Credit Facility. The interest amount calculated on the Credit Facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(4) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. Lease expense is charged to operating expenses on a straight line basis over the period of expected benefit. Contingent rental payments are expensed as incurred. Total rental expense for the three months ended September 30, 2011 and 2010 was $7.4 million and $5.7 million, respectively. For the nine months ended September 30, 2011 and 2010, total rental expense was $22.0 million and $16.2 million, respectively.

(5) Includes leases of space in office buildings and related land leases with respect to our Albany terminal.

(6) Includes BORCO facility leases for tugboats and a barge in our International Operations segment.

(7) Includes leases for inland dock and seabed in connection with our International Operations segment and leases for subsurface underground gas storage rights and surface rights in connection with our operations in

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the Natural Gas Storage segment. We may cancel the Natural Gas Storage segment leases if the storage reservoir is not used for underground storage of natural gas or the removal or injection thereof for a continuous period of two consecutive years. Lease expense associated with the Natural Gas Storage segment leases, which is being recognized on a straight-line basis over 44 years, was approximately $1.8 million for each of the three months ended September 30, 2011 and 2010 and $5.4 million for each of the nine months ended September 30, 2011 and 2010. At September 30, 2011 and December 31, 2010, the balance of our Natural Gas Storage segment deferred lease liability was $16.4 million and $13.3 million, respectively. We estimate that this deferred lease liability will continue to increase through 2032, at which time our deferred lease liability is estimated to be approximately $64.7 million. Our deferred lease liability will then be reduced over the remaining 19 years of the lease, since the expected annual lease payments will exceed the amount of lease expense.

(8) We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at September 30, 2011.

(9) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors for services rendered or products purchased.

In addition, our obligations related to our pension and postretirement benefit plans are discussed in Note 15 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements

There have been no material changes with regard to our off-balance sheet arrangements since those reported in our Annual Report on Form 10-K/A for the year ended December 31, 2010.

Related Party Transactions

With respect to related party transactions, see Note 17 in the Notes to Unaudited Condensed Consolidated Financial Statements.

Recent Accounting Pronouncements

See Note 1 in the Notes to Unaudited Condensed Consolidated Financial Statements for a description of certain new accounting pronouncements that will or may affect our consolidated financial statements.

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Market Risk Trading Instruments

We have no trading derivative instruments.

Market Risk Non-Trading Instruments

We are exposed to financial market risk resulting from changes in commodity prices and interest rates. BORCO s functional currency is the U.S. dollar and it is equivalent in value with the Bahamian dollar. Foreign exchange gains and losses arising from transactions denominated in a currency other than the functional currency relate to a nominal amount of supply purchases and are included in net income (loss) in the condensed consolidated statements of operations. The effects of foreign currency transactions were not considered to be material for the three and nine months ended September 30, 2011.

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Commodity Risk

Natural Gas Storage

The Natural Gas Storage segment enters into interruptible natural gas storage hub service agreements in order to maximize the daily utilization of the natural gas storage facility, while also attempting to capture value from seasonal price differences in the natural gas markets. Although the Natural Gas Storage segment does not purchase or sell natural gas, the Natural Gas Storage segment is subject to commodity risk because the value of natural gas storage hub services generally fluctuates based on changes in the relative market prices of natural gas over different delivery periods.

As of September 30, 2011, the Natural Gas Storage segment has recorded the following assets and liabilities related to its hub services agreements (in thousands):

	September 30, 2011
Assets:	
Hub service agreements	$ 20,685
Liabilities:	
Hub service agreements	(12,470)
Total	$ 8,215

Energy Services

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its physical commodity forward fixed-price purchase and sales contracts. The derivative contracts used to hedge refined petroleum product inventories are classified as fair value hedges. Accordingly, our method of measuring ineffectiveness compares the changes in the fair value of the New York Mercantile Exchange (NYMEX) futures contracts to the change in fair value of our hedged fuel inventory.

Our Energy Services segment has not used hedge accounting with respect to its physical derivative contracts. Therefore, our physical derivative contracts and the related futures contracts used to offset the changes in fair value of the physical derivative contracts are all marked-to-market on the consolidated balance sheet with gains and losses being recognized in earnings during the period. In addition, hedge accounting has not been elected for futures contracts that have been executed to economically hedge a portion of the Energy Services segments refined petroleum products held in inventory; therefore, the changes in fair value of the futures contracts are marked-to-market on the consolidated balance sheet with gains and losses being recognized in earnings during the period.

As of September 30, 2011, the Energy Services segment had derivative assets and liabilities as follows (in thousands):

	September 30, 2011
Assets:	
Physical derivative contracts for refined products	$ 7,202
Futures contracts for refined products	20,165
Liabilities:	
Physical derivative contracts for refined products	(1,656)
Total	$ 25,711

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The gains and losses recognized in income for ineffectiveness and excluding the time value component on our derivative instruments that are designated as fair value hedging instruments were as follows for the periods indicated (in thousands):

	Location	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
Fair value hedge ineffectiveness (excluding time value)	Cost of product sales and natural gas storage services	$ 3,825	$ 3,621
Time value excluded from hedge assessment	Cost of product sales and natural gas storage services	(1,353)	(9,697)
Net impact on income		$ 2,472	$ (6,076)

Our hedged inventory portfolio extends to the fourth quarter of 2011. The majority of the unrealized gain at September 30, 2011 for inventory hedges represented by future contracts will be realized by the fourth quarter of 2011 as the inventory is sold. At September 30, 2011, open refined petroleum product derivative contracts varied in duration in the overall portfolio, but did not extend beyond December 2012. In addition, at September 30, 2011, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

Based on a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at September 30, 2011, the estimated fair value of the portfolio of commodity financial instruments would be as follows (in thousands):

Scenario	Resulting Classification	Commodity Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying commodity prices (as is)	Asset	$ 25,711
Fair value assuming 10% increase in underlying commodity prices	Liability	$ (9,963)
Fair value assuming 10% decrease in underlying commodity prices	Asset	$ 61,385

The value of the open futures contract positions noted above were based upon quoted market prices obtained from NYMEX. The value of the physical derivative contracts was based on observable market data related to the obligation to provide refined petroleum products to customers.

As discussed above, these commodity financial instruments are used primarily to manage the risk of market price volatility on the Energy Services segment s refined petroleum product inventories and its physical derivative contracts. The derivative contracts used to hedge refined petroleum product inventories are classified as fair value hedges and are, therefore, expected to be highly effective in offsetting changes in the fair value of the refined petroleum product inventories.

Interest Rate Risk

We utilize forward-starting interest rate swaps to manage interest rate risk related to forecasted interest payments on anticipated debt issuances. This strategy is a component in controlling our cost of capital associated

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with such borrowings. When entering into interest rate swap transactions, we become exposed to both credit risk and market risk. We are subject to credit risk when the value of the swap transaction is positive and the risk exists that the counterparty will fail to perform under the terms of the contract. We are subject to market risk with respect to changes in the underlying benchmark interest rate that impact the fair value of the swaps. We manage our credit risk by only entering into swap transactions with major financial institutions with investment-grade credit ratings. We manage our market risk by associating each swap transaction with an existing debt obligation or a specified expected debt issuance generally associated with the maturity of an existing debt obligation.

Our practice with respect to derivative transactions related to interest rate risk has been to have each transaction in connection with non-routine borrowings authorized by the board of directors of Buckeye GP. In February 2009, Buckeye GP s board of directors adopted an interest rate hedging policy which permits us to enter into certain short-term interest rate hedge agreements to manage our interest rate and cash flow risks associated with the BPL Credit Facilities. In addition, in July 2009 and May 2010, Buckeye GP s board of directors authorized us to enter into certain transactions, such as forward starting interest rate swaps, to manage our interest rate and cash flow risks related to certain expected debt issuances associated with the maturity of existing debt obligations.

At September 30, 2011, we had total fixed-rate debt obligations at face value of $2,075.0 million, consisting of $300.0 million of the 4.625% Notes, $275.0 million of the 5.300% Notes, $125.0 million of the 5.125% Notes, $300.0 million of the 6.050% Notes, $275.0 million of the 5.500% Notes, $650.0 million of the 4.875% Notes and $150.0 million of the 6.750% Notes. The fair value of these fixed-rate debt obligations at September 30, 2011 was approximately $2,196.5 million. We estimate that a 1% decrease in rates for obligations of similar maturities would increase the fair value of our fixed-rate debt obligations by approximately $128.7 million.

At September 30, 2011, our variable-rate obligation was $592.5 million under the Credit Facility. Based on the balance outstanding at September 30, 2011, we estimate that a 1% increase or decrease in interest rates would increase or decrease annual interest expense by approximately $5.9 million.

We expect to issue new fixed-rate debt (i) on or before July 15, 2013 to repay the $300.0 million of 4.625% Notes that are due on July 15, 2013 and (ii) on or before October 15, 2014 to repay the $275.0 million of 5.300% Notes that are due on October 15, 2014, although no assurances can be given that the issuance of fixed-rate debt will be possible on acceptable terms. We have entered into six forward-starting interest rate swaps with a total aggregate notional amount of $300.0 million related to the anticipated issuance of debt on or before July 15, 2013 and six forward-starting interest rate swaps with a total aggregate notional amount of $275.0 million related to the anticipated issuance of debt on or before October 15, 2014. The purpose of these swaps is to hedge the variability of the forecasted interest payments on these expected debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. During the three months ended September 30, 2011, unrealized losses of $83.6 million were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the forward-starting interest rate swaps. During the nine months ended September 30, 2011, unrealized losses of $92.4 million were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the forward-starting interest rate swaps. We designated the swap agreements as cash flow hedges at inception and expect the changes in values to be highly correlated with the changes in value of the underlying borrowings.

On January 13, 2011, we issued the 4.875% Notes in an underwritten public offering. In December 2010, in connection with the proposed offering, we entered into a treasury lock agreement to fix the ten-year treasury rate at 3.3375% per annum on a notional amount of $650.0 million. In January 2011, we subsequently cash-settled the treasury lock agreement upon the issuance of the 4.875% Notes and received approximately $0.5 million, which is being recognized as a reduction to interest and debt expense over the ten-year term of the 4.875% Notes.

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The following table presents the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at September 30, 2011 (in thousands):

Scenario	Resulting Classification	Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying interest rates (as is)	Liability	$ (89,514)
Fair value assuming 10% increase in underlying interest rates	Liability	$ (74,870)
Fair value assuming 10% decrease in underlying interest rates	Liability	$ (105,630)

Item 4. ***Controls and Procedures***

(a) Evaluation of Disclosure Controls and Procedures.

Our management, with the participation of our Chief Executive Officer (the CEO) and Chief Financial Officer (the CFO), evaluated the design and effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the CEO and CFO concluded that our disclosure controls and procedures as of the end of the period covered by this report are designed and operating effectively to provide reasonable assurance that the information required to be disclosed by us in reports filed under the Securities Exchange Act of 1934, as amended, 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 the CEO and CFO, as appropriate to allow timely decisions regarding disclosure. A controls system cannot provide absolute assurance, however, that the objectives of the controls system are met, and no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within a company have been detected.

(b) Change in Internal Control Over Financial Reporting.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the third quarter of 2011 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

We closed the BORCO acquisitions on January 18, 2011 and February 16, 2011, and are evaluating the internal control structure of BORCO. We expect that evaluation to continue during the remainder of 2011. In recording the BORCO acquisitions, we followed our normal accounting procedures and internal controls. Our management also reviewed the operations of BORCO that are included in our earnings for the three and nine months ended September 30, 2011.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

For information on legal proceedings, see Part 1, Item 1, Financial Statements, Note 3, Commitments and Contingencies in the Notes to Unaudited Condensed Consolidated Financial Statements included in this quarterly report, which is incorporated into this item by reference.

Item 1A. ***Risk Factors***

Security holders and potential investors in our securities should carefully consider the risk factors set forth in Part 1, Item 1A. Risk Factors of our Annual Report on Form 10-K/A for the year ended December 31, 2010 in addition to other information in such report and in this quarterly report. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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Item 6. ***Exhibits***

(a) Exhibits

3.1	Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of February 4, 1998 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 1997).
3.2	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of April 26, 2002 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002).
3.3	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of June 1, 2004, effective as of June 3, 2004 (Incorporated by reference to Exhibit 3.3 of the Buckeye Partners, L.P. s Registration Statement on Form S-3 filed June 16, 2004).
3.4	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of December 15, 2004 (Incorporated by reference to Exhibit 3.5 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2004).
3.5	Amended and Restated Agreement of Limited Partnership of Buckeye Partners, L.P., dated as of November 19, 2010 (Incorporated by reference to Exhibit 3.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed November 22, 2010).
3.6	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Buckeye Partners, L.P., dated as of January 18, 2011 (Incorporated by reference to Exhibit 3.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 20, 2011).
4.1	Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).
4.2	First Supplemental Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.2 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).
4.3	Second Supplemental Indenture dated as of August 19, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.3 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).
4.4	Third Supplemental Indenture dated as of October 12, 2004, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on October 14, 2004).
4.5	Fourth Supplemental Indenture dated as of June 30, 2005, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 30, 2005).
4.6	Fifth Supplemental Indenture dated as of January 11, 2008, between Buckeye Partners, L.P. and U.S. Bank National Association (successor to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 11, 2008).
4.7	Sixth Supplemental Indenture dated as of August 18, 2009, between Buckeye Partners, L.P. and U.S. Bank National Association (successor-in-interest to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 24, 2009).
4.8	Seventh Supplemental Indenture dated as of January 13, 2011, between Buckeye Partners, L.P. and U.S. Bank National Association (successor-in-interest to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 20, 2011).

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4.9	Registration Rights Agreement, by and among Buckeye Partners, L.P., BGH GP Holdings, LLC, ArcLight Energy Partners Fund III, L.P., ArcLight Energy Partners Fund IV, L.P., Kelso Investment Associates VIII, L.P. and KEP VI, LLC (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 11, 2010).
4.10	Registration Rights Agreement by and among Buckeye Partners, L.P., FR XI Offshore AIV, L.P. and the other investors named therein, dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.4 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
4.11	Registration Rights Agreement by and among Buckeye Partners, L.P. and the investors named therein, dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.5 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
4.12	Registration Rights Agreement by and between Buckeye Partners, L.P. and Vopak Bahamas B.V. dated as of February 15, 2011 (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on February 22, 2011).
10.1	Buckeye Partners, L.P. 2009 Long-Term Incentive Plan, as amended and restated effective August 3, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 9, 2011).
10.2	Buckeye Partners, L.P. Unit Deferral and Incentive Plan, as amended and restated effective August 4, 2011 (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 9, 2011).
10.3	Revolving Credit Agreement, dated as of September 26, 2011, by and among Buckeye Partners, L.P., Buckeye Energy Services LLC, SunTrust Bank and other lenders party thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on September 30, 2011).
*31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14 (a) under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
*32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
*32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Taxonomy Extension Schema Document.
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Filed herewith.
Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Buckeye agrees to furnish supplementally a copy of the omitted schedules to the SEC upon request.

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SIGNATURES

Pursuant to the requirements of Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	By:	BUCKEYE PARTNERS, L.P. (Registrant)
	By:	Buckeye GP LLC, as General Partner
Date: November 8, 2011	By:	/s/ Keith E. St.Clair Keith E. St.Clair *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer)*